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Readying Michigan to Make Good Energy Decisions:

Additional Areas

DRAFT

October 1, 2013

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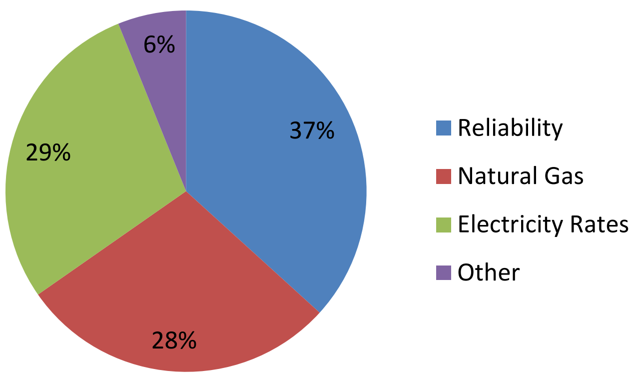
Readying Michigan to Make Good Energy Decisions – Additional Areas
Executive Summary

The Additional Areas report covers miscellaneous energy questions that were not classified as pertaining specifically to renewable energy, energy efficiency or electric choice. The 15 renewable energy questions posted on the Ensuring Michigan's Energy Future website garnered 49 responses. The comment summary pie chart presents an overview of comments received in response to the questions through the website. Many additional comments covering these topics were given at the public energy forums.



Where Michigan Is Today:
Electric reliability is regulated at both the federal (FERC and NERC) and the state (Michigan Public Service Commission or MPSC) levels. The current status of electric reliability in Michigan is considered to be "more than adequate" by respondents. In recent years, Michigan's electricity rates have risen to levels that are higher than the national average, and also higher than surrounding Midwest states. The current law requires rates to be set at the cost of service and allows utilities to self-implement rate increases in as little as six months after application and requires that utility rate cases be completed within one year. Michigan has access to natural gas from multiple basins via pipeline infrastructure as well as access to stored gas via underground storage located within the state.

<u>Electric Reliability</u>

- Electric reliability is about keeping the lights on. The North American Electric Reliability Corporation's (NERC) definition of reliability includes both adequacy and security.
    - NERC is the electric reliability organization (ERO) delegated by the Federal Energy Regulatory Commission (FERC) as provided for in the Energy Policy Act of 2005, which made reliability standards for the bulk power system (generally consisting of power plants and higher voltage electric lines) mandatory and enforceable.
    - Adequacy refers to having adequate resources such as generation or demand response resources to meet peak electric demand.
    - Security refers to reducing the system's vulnerability to interruptions to keep both the transmission system and distribution system running smoothly. Electric transmission reliability and electric distribution reliability are both components of security.

- Regional reliability: The majority of Michigan is within the Midcontinent ISO's (MISO) footprint, while a small portion of Southwest Michigan is within the PJM footprint. MISO and PJM are regional transmission operators approved by the FERC.
    - MISO and PJM both calculate the amount of electric generation and demand side resources required to provide an adequate supply of electricity within each region.
    - MISO and PJM each dispatch electric generation that resides within its footprint.
    - MISO and PJM are continuously monitoring the reliability of the transmission system.
    - MISO and PJM facilitate transmission planning for each region in accordance with NERC standards.
    - MISO and PJM approve transmission plans for each region, including transmission to interconnect new generation; however, MISO and PJM do not plan or approve new generation resources.
- Regulating electric reliability in Michigan at the MPSC:
    - MPSC staff participates in regional workgroups addressing adequacy and transmission planning.
    - The MPSC has distribution reliability rules for regulated entities within the state that are in addition to traditional distribution reliability indices.
    - The MPSC annually requests load-serving entities to make a showing that they have secured adequate resources to meet the upcoming summer peak.
    - Public Act 286 provides the MPSC with the authority to grant a certificate of need for generation within the state.
    - Public Act 30 provides the MPSC with the authority to grant a certificate of necessity for transmission within the state.
- ITC, the largest transmission company in Michigan, commented that it has made more than $2 billion in capital investments in transmission infrastructure in the Lower Peninsula of Michigan, and its region in the Lower Peninsula is ranked in the top decile in the industry for reliability.
- Over the last six years the American Transmission Company (ATC), that is responsible for the transmission system in the Upper Peninsula (UP), has built a series of 138 kV and 345 kV transmission lines to foster more reliable service in the UP. In order to improve on the ability to move energy efficiently from Lower to Upper Peninsula, ATC recently installed phase angle regulators (PARS) at the Straits of Mackinac to improve control of electric flows between the peninsulas, which in turn increases reliability.

<u>Electricity Rates and Utility Ratemaking</u>

- Michigan's electricity rates were above the national average during the 1990s, below the national average during the 2000s, and today are higher than the national average. The utilities report that rate comparisons across states are largely explained by different states' relative exposure to fluctuating natural gas prices.
- When comparing electricity rates over time, the utilities report that load loss appears to have had the largest impact on rates. As load decreases, whether due to customers leaving utility service to switch to an alternative electric supplier (choice) or leaving the system entirely, there are fewer customers and lower sales over which to spread the fixed costs of a utility. This leads to higher rates for those customers who remain with utility service.

- The utilities also report that fuel costs have had the second largest impact on rates since 2008. Fuel prices impact the electricity prices that are ultimately paid by customers.
    - Michigan's total coal costs increased 96% from 2004 to 2012, yet were in line with neighboring Great Lakes states during this time.
    - Several reasons for the increases in Michigan's delivered costs of coal were reported, including transportation costs, production costs and increased coal exports.
- The utilities also report that the elimination of cross-class subsidies, environmental upgrades, base system investment, renewable energy investment, and energy efficiency investment have all had upward pressure on residential rates. The cross-class subsidy elimination helped to offset the rate impact to industrial and commercial customers, and reductions in operating costs and the cost of the capital also lessened the rate impact for all customer classes.
- While Michigan's electricity rates are higher than many other states, Michigan residential customers generally use less electricity, which results in lower bills.
- The utilities identify three other factors that, combined, explain an additional 25% of the variation in average rates between states; proximity to low-cost coal, access to inexpensive hydroelectric generation, and lack of coal-fired generation.
- Dow and the Association of Businesses Advocating Tariff Equity claim that self-implementation has had a negative effect on rates.
- Dow also points out that Michigan's electric rates are the highest in the Midwest, making the state less attractive to manufacturers, and inhibiting the jobs and economic multiplier effect manufacturers could provide.
- "Economic development rates" are available in other states. The utilities state they should have the discretionary ability to offer economic development rates, appropriately designed, with MPSC oversight. Traditionally, the objection to these rates is that they often represent a subsidy by other customers and violate "cost of service" principles.

Natural Gas Infrastructure

- Michigan producers supply 15 – 20% of the natural gas that is used in Michigan.
- Michigan also receives gas from the Texas-Oklahoma panhandle, Louisiana and Canada. Michigan also has the capability to receive gas from the Rockies and the Marcellus regions.
- In order to affordably access Michigan's gas potential, hydraulic fracturing is necessary. Many oral and written comments and concerns regarding the safety and environmental impact of hydraulic fracturing were received in this process. The Graham Sustainability Institute at the University of Michigan has released technical reports for comment regarding hydraulic fracturing in Michigan.[1]
- With about 649 billion cubic feet of storage capacity, Michigan has more than any other state. Because natural gas can be put into storage during the summer months when there is less demand, it allows for more efficient use of transmission pipelines and helps stabilize prices.

[1] http://graham.umich.edu/knowledge/ia/hydraulic-fracturing.

- Theoretically there is room for gas storage expansion in Michigan because there are depleted gas reservoirs that could be converted to storage if it is economically feasible to do so. The economic feasibility usually depends on the location of the reservoir and its geologic characteristics. In many cases, there would need to be more infrastructure and pipeline capacity added in order to convert and utilize these reservoirs.
- Currently, there is sufficient in-state pipeline capacity to move natural gas around the state and to satisfy Michigan's demand as a whole.
- Currently, the relatively low price of gas and the increase in shale production provides increased incentive to use gas for applications other than heating. Specifically, Michigan is currently experiencing a compliance push to retire and replace coal fired electric generation with natural gas fired generation, mainly due to environmental regulations and the price of natural gas.
- Natural gas-fired electric generating plants are considered to be economically and operationally viable.

<u>Summary</u>

- This report outlines some additional areas within the energy policy space that could be considered when reviewing future energy policy, including reliability, electricity rates and prices, and natural gas infrastructure.
- While developing a cohesive future energy policy for Michigan in the areas of renewable energy policy, energy efficiency policy, and electric choice policy, the additional areas outlined in this report should be taken into consideration.

Section I - Background and Approach

Background

On November 28, 2012, Governor Snyder delivered a special message on Energy and the Environment. Appendix A to the special message requested that members of the Legislature, as well as interested Michiganders, communicate what information they believe is needed to make good decisions regarding our energy choices beyond 2015. The administration specifically sought input on energy efficiency and renewable energy policies, as well as the future of electric choice. Appendix A summarizes the process the administration put into place for 2013 to ensure that this information is collected and available in a timely fashion for policy makers.

The administration convened a series of public participation opportunities around the state that were co-chaired by the Chairman of the Michigan Public Service Commission (MPSC), John Quackenbush, and the director of the Michigan Energy Office, Steven Bakkal. In addition to the areas of energy efficiency, renewable energy and electric choice, the MPSC and Michigan Energy Office sought input on miscellaneous topics related to electric rates and utility ratemaking, natural gas infrastructure, and reliability. These topics fall under the category referred to as Additional Areas, and are the subject of this report.

Objective and Approach

The purpose of this report is to provide a summary of the public comments submitted in response to the Additional Area questions through the statewide process. This includes public questions and comments that can be found at the Michigan.gov/energy website.[2] Comparatively, significantly lower numbers of comments and submissions were received in response to the questions on the Additional Areas than were received for the questions on renewable energy, energy efficiency or electric choice. A total of 49 responses were received to the 15 Additional Area questions on the website. This report is based on those comments and does not attempt to recommend any particular policy. Instead, it provides a summary and analysis of the comments submitted.

[2] http://www.michigan.gov/energy/0,4580,7-230-63813---,00.html.

Section II – Policy Considerations

The Additional Area questions address several issues, but could be grouped into several broad themes. Each of the questions posed addresses various facets of electric reliability, utility rates and prices of electricity, or natural gas infrastructure.

Electric Reliability

Electric reliability is critical to national safety, security, health, and economic prosperity. Reliability is an economic "public good," with enormous (and immeasurable) societal benefits. Commenters discussed local distribution reliability, transmission reliability, supply adequacy, regional transmission organizations, and local issues affecting the Upper Peninsula.

There were very few comments addressing reliability issues and no major concerns expressed. Notwithstanding, this section provides additional background on the topic for policy makers, given the complexity and importance of maintaining a reliable electric system.

Defining Reliability

In its simplest form, electric reliability has been defined as the ability to instantaneously match electricity generation with customer demand (load). To those in the industry, reliability takes on a much more intricate definition that conveys the true complexity of the electric grid. A majority of commenters from the Michigan Energy Forum referenced the North American Electric Reliability Commission (NERC)[3] definition of reliability as the current definition used by policy makers. NERC is the electric reliability organization (ERO) delegated by the Federal Energy Regulatory Commission (FERC) as provided for in the Energy Policy Act of 2005[4] which made reliability standards for the bulk power system (generally consisting of power plants and higher voltage electric lines) mandatory and enforceable. NERC's members include electric utilities, transmission owners and market participants from all segments of the industry across the continental U.S., Canada and northern Mexico.

According to NERC, electric reliability is composed of two elements: adequacy and security. **Adequacy** refers to having enough resources available to meet demand. **Security** involves the various protections that keep the system functioning smoothly – reducing and minimizing its vulnerability and enabling it to respond to emergencies. It entails a minute-by-minute view of system needs. Among others, electric distribution reliability and transmission reliability are both components of security.

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[3] *See:* www.nerc.com; The North American Electric Reliability Corporation is a not-for-profit entity whose mission is to ensure the reliability of the Bulk-Power System in North America. NERC develops and enforces Reliability Standards; annually assesses seasonal and long-term reliability; monitors the Bulk-Power System through system awareness; and educates, trains and certifies industry personnel.

[4] *See:* http://www.nerc.com/AboutNERC/keyplayers/Documents/Summary_of_Reliability_Legislation-20050808.pdf.

Adequacy

Electricity demand fluctuates as lights, appliances, industrial motors, etc., turn on and off. With each flip of a switch, electric generating resources are dispatched to ramp up or down to meet this demand, 24 hours per day, 365 days per year. Some of those hours, such as nights and weekends, require fewer generating resources to be available and running, as compared to the afternoon of the hottest day of the year.

In the electric power sector the term Resource Adequacy refers to the ability to meet end-use demand for electric power during system peak hours when electricity consumption is highest. In general, the system is designed to meet peak demand by adjusting quantity rather than reducing demand through price signals. Most retail customers typically pay the same rate on a peak day as they would on any other day. However, more expensive power plants are called on to run during the peak and, if demand still cannot be met, consumption can be cut through rolling brownouts and other steps that reduce demand. Without the availability of these higher cost plants and demand-reducing steps, a total loss of power (blackout) could occur.

"Extra" electric generation capacity above and beyond the expected demand for electricity is required so that power is available to meet demand when a power plant is down for maintenance or accidentally trips off. The amount of extra generation capacity required in each area is often called a planning reserve margin and is based on criteria set by the Regional Electric Reliability Councils.[5] Maintenance of a planning reserve margin helps to ensure that the lights will stay on.

The federal Energy Policy Act of 2005 directs the ERO (NERC) to assess and periodically report on the adequacy of the bulk-power system, but it also states that the ERO does **not** have the authority to set or enforce mandatory standards for adequacy. The Energy Policy Act of 2005 does not give the ERO or FERC the authority to require the expansion of generation or transmission. The approval for new generation or distribution typically occurs at the state or local level, while the approval of new transmission typically occurs at the regional level along with certifications and permits that may be required at the state or local level.

Distribution Reliability *(Security)*

The electric distribution system delivers electricity from substations to businesses and residences. Electric service to a business or residence may become interrupted for a multitude of reasons such as severe weather, tree limb interference with power lines, overloaded circuits or an accident such as a vehicle striking a pole. Electric outages have huge economic

[5] Regional Electric Reliability Councils are delegated by NERC to assist with reliability standard development and compliance. Underlying most resource adequacy guidelines in the United States are criteria set by the Regional Electric Reliability Councils, typically a "1 in 10 Loss of Load Expectation" or LOLE. Each area's resources should be planned in such a manner that the probability of disconnecting non-interruptible customers will be no more than once in 10 years. This analysis considers numerous factors such as scheduled outages, power imports from neighboring regions, and load shedding (for interruptible customers) procedures.

implications for customers even when only lasting minutes. Therefore, avoiding and otherwise mitigating the number and extent of power outages is a key concern for policy makers. The power outage serves as the foundation of nearly every reliability index and provides an easily identifiable event from which to measure system performance and develop industry standards. The most common of these standards used by utility policy makers are the Institute of Electrical and Electronics Engineers (IEEE) Standard 1366. This standard provides a guide from which electric utilities can calculate multiple distribution reliability indices regarding outage frequency and duration. These indices can be benchmarked against other utilities and provide an ongoing record of individual system performance.   The most common of the IEEE reliability indices used by policy makers to define reliability are: System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), and Customer Average Interruption Frequency Index (CAIDI).[6]   These metrics provide regulators insight into the significance of outages on a utility system and the utility's ability to react to outages and effectively restore service. The three reliability metrics are defined as:

$$\text{SAIFI} = \frac{\text{Total Number of Customers Interrupted}}{\text{Total Number of Customers Served}}$$

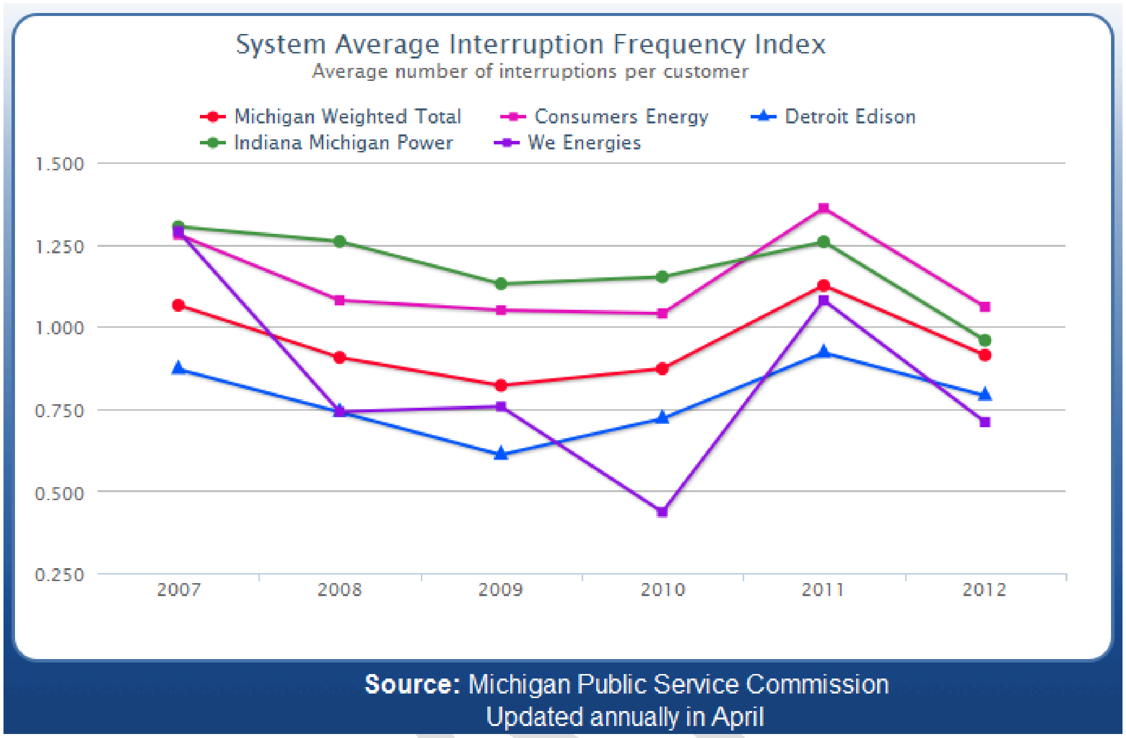
$$\text{SAIDI} = \frac{\text{Customer Interruption Durations}}{\text{Total Number of Customers Served}}$$

$$\text{CAIDI} = \frac{\text{Customer Interruption Durations}}{\text{Total Number of Customers Interrupted}}$$

As part of Governor Snyder's Energy and Environment Dashboard, SAIFI is tracked for several Michigan utilities.[7] Lower SAIFI scores indicate higher levels of electric distribution reliability.

[6] The two largest regulated utilities in Michigan have been required to report these reliability metrics to the MPSC yearly most recently in Docket Nos. U-16065 and U-16066.
[7] *See:* http://www.michigan.gov/midashboard/0,4624,7-256-63322_63324_63332---,00.html.

Figure 1: System Average Interruption Frequency Index (SAIFI)



Severe weather patterns can impact SAIFI; however, Michigan utilities have had fairly consistent distribution reliability performance for the past several years. Michigan utilities commented that while distribution reliability in Michigan is adequate, the infrastructure is aging.

Electric distribution reliability is important because power outages may affect the security and safety of residents within a community. Also, the costs associated with power outages affect Michigan businesses and may impact decisions for businesses to expand or locate in Michigan.

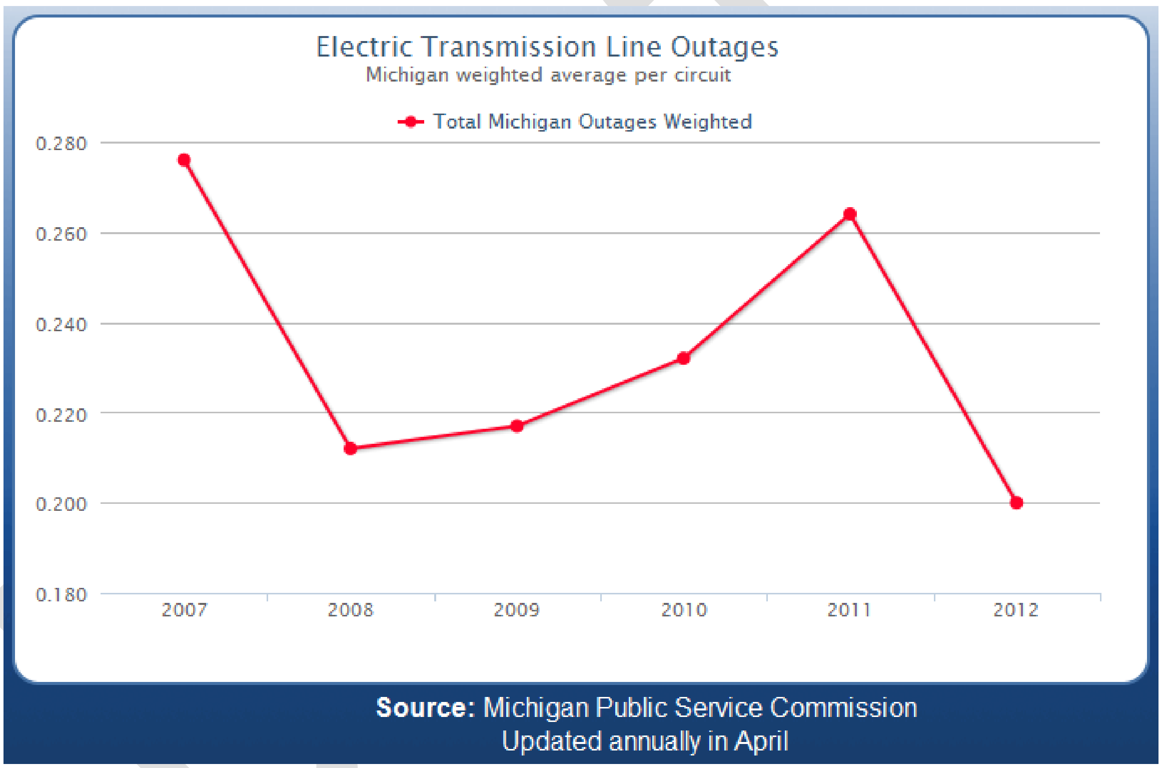
Transmission Reliability *(Security)*

Transmission refers to the high-voltage wires and networks that move electricity through states and regions in large quantities -- from power plants where it is produced, to the distribution networks that deliver it to homes and businesses. Transmission is like our region's interstate highways, while the distribution system is similar to our local roadways. Due to the fact that transmission lines serve multiple distribution utilities spanning multiple jurisdictions, transmission reliability is monitored at the regional level by NERC. The primary measure of transmission reliability is adherence to NERC reliability standards. NERC Reliability Standards define the reliability requirements for planning and operating the North American Bulk-Power System and are developed using an approach that focuses on performance, risk management, and entity capabilities. These NERC reliability standards are enforced by way of significant financial penalties for noncompliance, up to $1,000,000 per instance, per day.

Electric transmission outages occur much less frequently than electric distribution outages. This is due in part to the significant emphasis placed on planning and operating the transmission system under mandatory NERC reliability standards. Many times, a single line outage on the transmission system does not result in power outages for customers as multiple paths are available through the interconnected grid. In other words, there are some redundancies built into the system. Lower levels of transmission line outages help to ensure high levels of electricity reliability for retail customers.

As part of Governor Snyder's Energy and Environment Dashboard, transmission outages in Michigan are tracked.[8]

Figure 2: Transmission Line Outages



Michigan utilities commented that transmission reliability in Michigan is more than adequate. ITC, the largest transmission company in Michigan, commented that it has made more than $2 billion in capital investments in transmission infrastructure in the Lower Peninsula of Michigan, and its region in the Lower Peninsula is ranked in the top decile in the industry for reliability. Wolverine submitted specific comments related to the Upper Peninsula that are discussed later in this report.

[8] *See:* http://www.michigan.gov/midashboard/0,4624,7-256-63322_63324_63333---,00.html.

Roles and Responsibilities for Maintaining Reliability

While electricity reliability is very important to the state of Michigan, it is important to recognize that many different entities are involved with regulating reliability. Federal entities, such as the FERC and NERC, regional entities, states, and in some instances, local entities have roles in maintaining a reliable electric system.

Regional Reliability

The traditional model of the vertically integrated electric utility with a transmission system designed to serve its own customers worked extremely well for decades. As dependence on a reliable supply of electricity grew and electricity was transported over increasingly greater distances, power pools were formed and interconnections developed. Transactions were still relatively few and generally planned well in advance. Regional Transmission Operators (RTOs) were created by the FERC as a way to handle the challenges associated with the operation of multiple interconnected independent power supply companies.

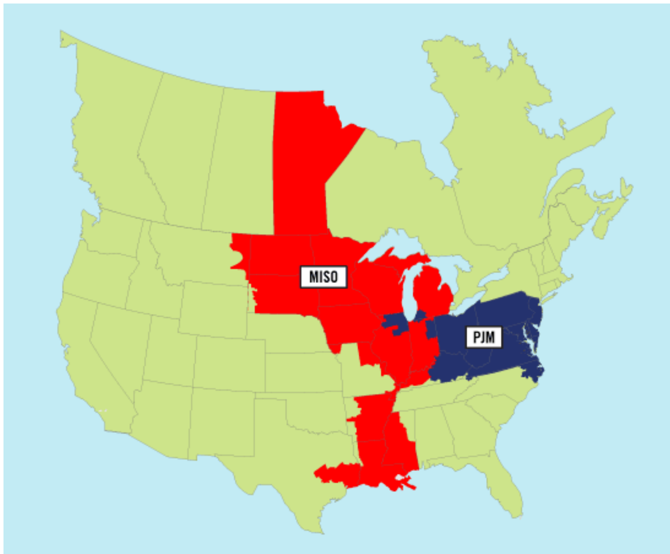
In June 2000, the Michigan Legislature passed Michigan's Customer Choice and Electric Reliability Act, 2000 PA 141 (Act 141) that established a framework to allow retail customers to choose an alternative electric supplier (AES) to provide their electric generation service in the state. However, the electric generation and distribution businesses of the bundled utilities remained under a regulated monopoly utility structure. As a result, Michigan exhibits characteristics of both a regulated market and a deregulated market and is commonly referred to as a hybrid structure.

The MPSC participates in regional efforts to support reliability of the electrical grid throughout Michigan's Upper and Lower Peninsula. Michigan's utilities belong to two RTOs: the Mid-continent Independent System Operator (MISO), and the PJM Interconnection, LLC. (PJM). A small portion of Southwest Michigan is served by the Indiana Michigan Power Company, a PJM member. The RTOs are responsible for coordinating, controlling and monitoring the electricity transmission grid at voltages higher than the typical energy provider's distribution system. The RTOs are also responsible for dispatching electric generation in a security-constrained economic dispatch, which means that the least cost generation is dispatched to meet the demand, while meeting the physical operating limitations of the transmission system.

An RTO is both a transmission operator and a transmission planner that must adhere to NERC reliability standards for operations and planning. The RTOs also plan future transmission upgrades to ensure that the reliability of the system is maintained and that NERC transmission planning standards are met. Part of NERC's oversight of the bulk electric system requires an open and transparent transmission planning process that ultimately ties the state regulated distribution level grid to the generators. This requirement has led to the MPSC's participation in the Mid-continent Independent System Operator's (MISO) Transmission Expansion Planning

(MTEP) process. The MISO and PJM footprints are shown below; MISO is shaded red and PJM is shaded blue.

Figure 3: Geography of MISO and PJM



The annual MISO Transmission Expansion Plan (MTEP) is intended to identify solutions to meet transmission reliability needs efficiently. MISO engages with stakeholders through a comprehensive planning process to identify transmission projects necessary to provide reliable service over the near- and long-term.

MISO also publishes an annual report that identifies the smallest planning reserve margin that is necessary for reliable operations in the MISO footprint. Load-serving entities within MISO including utilities and alternative electric suppliers (choice suppliers) are then required by MISO to provide enough physical or contracted resources to meet their projected electricity demand plus the reserve margin for the upcoming year. While MISO only requires a showing of adequate capacity one year in advance, PJM operates a three-year forward capacity market where load-serving entities must make a similar showing of adequate capacity for the upcoming three year period through self-supply options or by participation in PJM's Reliability Pricing Model (RPM) capacity auctions.

National and regional entities such as MISO publish reports on national and regional supply adequacy and transmission reliability.[9] While NERC and MISO publish reports on adequacy,

[9] *See:* 2013 NERC Long Term Reliability Assessment (LTRA), http://www.nerc.com/docs/risc/Item%202.b.iv%20-%202013%20Reliability%20Assessments%20Publication%20Schedule.pdf,
See: 2012 MISO Transmission Expansion Planning, https://www.midwestiso.org/Planning/TransmissionExpansionPlanning/Pages/MTEP12.aspx,
See: 2013 MISO Loss of Load Expectation, https://www.midwestiso.org/Library/Repository/Study/LOLE/2013%20LOLE%20Study%20Report.pdf.

they do not have the authority to require the construction of new generation or transmission. Comments were made at public forums in support of the need for regional markets to provide the price incentives necessary to attract investment in new generation to be able to meet resource adequacy needs reliably. Others commented that deregulated markets did not provide enough certainty surrounding future revenues that would be necessary in order to obtain financing for capital intensive investments in electricity generation.

<u>Regulating Electric Distribution Reliability in Michigan</u>

At the Michigan Public Service Commission, electric distribution reliability is regulated through several processes. The first is through the approval of capital and operations and maintenance expenditures related to reliability-based programs (i.e. line clearing, asset replacement) in a rate case. The Commission reviews testimony and metrics such as SAIDI, SAIFI, and CAIDI to measure the need for increased reliability and the prudency of proposed reliability investments. Reliability is also regulated at the MPSC through the enforcement of the Service Quality and Reliability Standards for Electric Distribution Systems. These standards are used to define the reliability expectations for regulated utilities operating in the State of Michigan. Four reliability rules from these are included as Appendix 1. The MPSC also initiates investigations related to electric distribution reliability, such as "The Report on the Status of Power Quality in Michigan, September 1, 2009."[10]

<u>Regulating Adequacy in Michigan</u>

On an annual basis, the MPSC issues an order requiring all regulated electric utilities and alternative electric suppliers to file assessments of their ability to meet peak system load expectations for the upcoming peak summer months. These reports provide the MPSC with information to assess the near-term adequacy of electric supply in the state.

The MPSC staff participates in regional workgroups at both MISO and PJM where planning reserve margin requirements are established. The MPSC staff also monitors the regional capacity markets along with seasonal and long-term adequacy assessments issued by NERC and regional organizations.

In years past, the MPSC has participated in Michigan specific studies evaluating future electric generation needs in Michigan, including the 21st Century Energy Plan[11] released in 2007. Since

[10] *See*: The Report on the Status of Power Quality in Michigan, http://michigan.gov/documents/mpsc/MPSC_Report_on_Status_of_Power_Quality-Sept09_290870_7.pdf?20130709134044.

[11] Among other things, the 21st Century Energy Plan identified the need for new resources to meet customer demand and recommended a new coal plant by 2015 and investments in energy efficiency and renewable energy. After 2007, customer load growth fell due to an economic downturn, and natural gas prices fell due to the shale revolution. However, the overall planning process and modeling in the 21[st] Century Energy Plan considered alternative scenarios to account for different consumption growth patterns and price forecasts for various fuel

2007, several key assumptions underlying the 21st Century Energy Plan recommendations have changed due primarily to the rapidly changing landscape for natural gas that began around 2008 with the emergence of new extraction methods and the prolonged recession. A revised state-wide assessment has not been undertaken. Some commenters at the public forums suggested that state wide resource planning is a useful endeavor when considering future electric supply (or demand) resource needs, including scenario analysis considering future variables and different options available.

Changes in PA 286 of 2008 provide a framework for planning at the individual utility level in certain circumstances. Specifically, the law requires a utility to assess its own future generation needs if it elects to file an application with the MPSC for a certificate of necessity (CON). Electric utilities that propose to invest in generation where the investment cost is $500,000,000 or more and a portion of the costs would be allocable to retail customers in the state may request a CON from the Commission to approve one or more of the following:

(a) A certificate of necessity that the power to be supplied as a result of the proposed construction, investment, or purchase is needed.
(b) A certificate of necessity that the size, fuel type, and other design characteristics of the existing or proposed electric generation facility or the terms of the power purchase agreement represent the most reasonable and prudent means of meeting that power need.
(c) A certificate of necessity that the price specified in the power purchase agreement will be recovered in rates from the electric utility's customers.
(d) A certificate of necessity that the estimated purchase or capital costs of and the financing plan for the existing or proposed electric generation facility, including, but not limited to, the costs of siting and licensing a new facility and the estimated cost of power from the new or proposed electric generation facility will be recoverable in rates from the electric utility's customers.

The CON request is reviewed in a contested case and requires the Commission to issue an order granting or denying the application within 270 days of the application. Some commenters provided details on competitive procurement procedures used in other jurisdictions should updates to the provisions in PA 286 of 2008 be considered. The Union of Concerned Scientists commented that power system interdependencies and vulnerabilities to extreme weather should be considered in utility planning.

prices and generation technologies. These included assumptions of low growth in electricity consumption and low natural gas prices.

Regulating Transmission Reliability in Michigan

Electric transmission is primarily regulated at the federal level by the FERC and also NERC for reliability purposes. As previously discussed, the MPSC participates in regional workgroups and monitors regional and national reports regarding the reliability of the electric grid. The state of Michigan does not directly regulate electric transmission, but the MPSC plays a key role in approving certain electric transmission line applications.

Electric transmission lines are essential to ensure the delivery of power in a reliable manner. In some instances, transmission infrastructure is also built for economic reasons in order to provide access to lower-cost generation sources and thereby reduce the cost of energy that is delivered to the end user. The cost of transmission investment can be substantial and the siting of new lines can be controversial due to challenges from nearby landowners and/or local governments. Generally, the transmission company and the landowners are able to reach agreement and avoid legal condemnation proceedings.

In 1995, Michigan enacted a new law, Public Act 30 (Electric Transmission Line Certification Act), which provides the MPSC authority to grant or deny an application for a certificate of public convenience and necessity for new transmission lines. The need for and routing of the line are examined through the certification process, which is handled as a contested case proceeding before the MPSC. The certificate takes precedence over conflicting local ordinances that prohibit or regulate the location or construction of the transmission line. For purposes of an eminent domain (condemnation) proceeding, the certificate is "conclusive and binding as to the public convenience and necessity for that transmission line and its compatibility with the public health and safety." (MCL 460.570(3))

In 2008, Michigan enacted a provision as part of PA 295 for expedited certification of transmission lines within designated Wind Energy Resource Zones. The expedited process under 2008 PA 295 must be concluded within 180 days (compared to one year under PA 30) and relies on alternative criteria for approval. ITC's "Thumb loop" transmission project in Michigan's Thumb region was approved under the PA 295 provisions.

Michigan's PA 30 framework is generally consistent with other states. ITC submitted a link to survey results of transmission siting policies from the Organization of MISO States, which includes Michigan and neighboring states.[12] State siting law applies to transmission lines in all 11 states that responded to the survey. Most of the states indicated that they have state authority to issue or deny construction permits for power transmission lines. In most states, limitations on the scope of state authority are related to voltage levels and line length, although in Iowa, municipalities have authority over lines within their boundaries. Other factors, such as whether there is landowner consent to construct the line, are also relevant in Montana. Six

[12] *See*: http://www.misostates.org/files/WorkGroups/SurveyResponsesAppendixB.pdf.

states indicated that they have a one-stop process, but in five of these states, the state authority either has primacy or there are additional steps, such as separate environmental reviews.

Upper Peninsula Reliability Issues

Due to its geography and climate, the Upper Peninsula (UP) has long been a challenging region in which to provide reliable electric service. In recent history, numerous reliability issues have presented challenges for utilities and their customers in the UP including: fuel procurement, limited ability to import/export power, water availability for hydro-electric generation, overloaded lines, low system voltage, and aging infrastructure. All of these issues have hindered the ability to meet the increasing electric demand and has affected growth in the area. Over the last six years the American Transmission Company (ATC), which is responsible for the transmission system in the UP, has built a series of 138 kV and 345 kV transmission lines to foster more reliable service in the Upper Peninsula. These transmission lines provide electric supply from Wisconsin to the Upper Peninsula through its western corridor. In order to improve on the ability to move energy efficiently from Lower to Upper Peninsula, ATC recently installed phase angle regulators (PARS) at the Straits of Mackinac to improve control of electric flows between the peninsulas, which in turn increases reliability.

As new and pending EPA regulations threaten the continued viability of generators in the region, MISO is conducting studies and proposing economic transmission solutions to provide safe, economic, and reliable service to the Upper Peninsula. Proposed projects and their drivers are detailed in both MISO's Northern Area Study[13] (part of the MTEP) and in the ATC 10 Year Plan.[14] Annual planning studies such as the ATC 10 Year Plan and the MTEP will continue to identify and correct current and future reliability concerns in the Upper Peninsula and ensure reliable electricity delivery to the area into the future.

RTO Coordination and Governance Issues

RTOs such as MISO and PJM operate and plan transmission systems to meet NERC reliability standards and the reliability needs of the region. In completing its mission, an RTO coordinates with other RTOs at seams that exist at the boundaries between two RTOs. RTOs also complete tasks, including some reliability related tasks such as transmission plan approvals or adequacy assessments, through different levels of stakeholder participation and governance. Michigan customers are located in the RTO chosen by the incumbent transmission utility, they are subject to the RTO transmission provider tariffs and their associated voting rights, transmission project planning and cost allocation methodologies, and energy and capacity market structures and requirements that are different for MISO and PJM.

Seams management between RTOs is handled primarily by Joint Operating Agreements between the involved RTOs and their respective neighbors. These agreements tend to maintain the status quo within

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[13] *See:* MISO Northern Area Study 2013, https://www.misoenergy.org/Library/Repository/Study/MTEP/MTEP13/Northern%20Area%20Study%20Final%20Report.pdf.
[14] *See*: ATC 10 Year Assessment Zone 2, http://www.atc10yearplan.com/blog/zones-directory/zone-2/.

each distinct RTO except for a few defined areas. That is, they attempt to coordinate the processes and requirements of the RTOs but not really merge or otherwise alter them to ensure greater consistency. Efforts are under way at FERC, the RTOs, and the states to attempt to further address seams issues. The MPSC and stakeholders continue to participate in these forums.

The comments addressed governance structures of PJM and MISO. The joint utility comments pointed out that the voting structure of MISO and PJM are similar for policy recommendations, but very different for the election of Board members. For MISO Board member elections, each dues-paying MISO member has one vote, and each vote has the same value as every other vote. In PJM, each company gets one vote for Board elections, but that vote is weighted according to provisions in the PJM Operating Agreement. One of the primary differences between the PJM and MISO stakeholder process is that PJM stakeholders must approve all tariff changes before they are filed with FERC; MISO stakeholder votes on tariff changes are only advisory.

MISO stakeholders are organized into nine sectors comprised of dues-paying members and non-paying members. All members have voting rights. Each MISO stakeholder has one vote as an individual member in the lower level committee process. Each MISO sector is assigned a number of seats (votes) in the higher level Advisory Committee process where Sector representatives vote on behalf of their respective sector membership. PJM has two types of members: affiliate members and associate members. The associate members include state regulatory commissions. Affiliate members have voting privileges. Associate members may attend stakeholder meetings and voice opinions, but do not have voting privileges. Thus, in contrast to MISO, state regulators do not have a formal vote in PJM.

Michigan represents approximately 20.7% of the total load in the MISO service territory and approximately 0.21% of the total load in the PJM service territory.

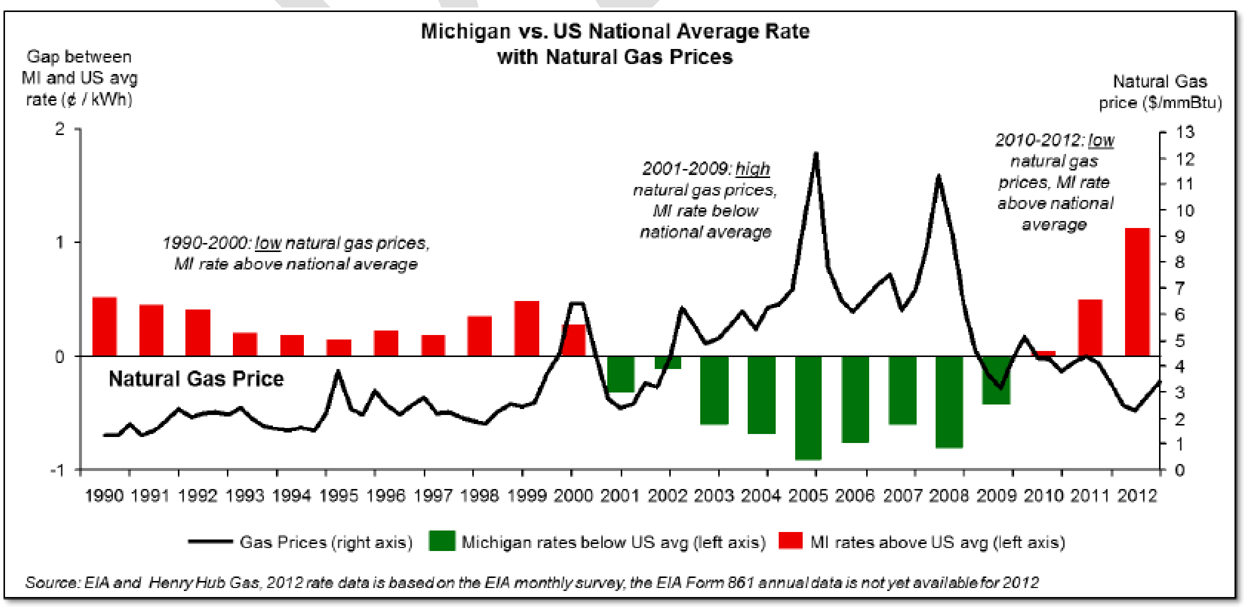
Rates and Prices for Electricity

Several of the Additional Area questions inquire about Michigan electricity rates. Commenters discussed changes to Michigan electricity rates over time, various triggers impacting electricity rates, and rate case processing. Several questions regarding electricity rates and prices are also addressed in the Draft Report on Electric Choice to be released in October 2013.

Michigan Electricity Rates

During the 1990s Michigan electricity rates were higher than the national average. During the 2000s, Michigan electricity rates were lower than the national average. Following 2009, Michigan's electricity rates crossed above the national average and remain above the national average today. The utilities claim that Michigan's rates, relative to other states and the national average, have fluctuated with the price of natural gas. The rates of other states tend to track the cost of natural gas relative to other fuel sources, as those states have significant natural gas-fired generation. Michigan, however, has relatively fewer natural gas-fired plants and, therefore, has not benefitted as much from the recent low natural gas prices. States with deregulated generation are the most sensitive to variable fuel prices, given the market price is determined by the highest cost unit. The utilities also show that Michigan's electric rates are lower than the majority of deregulated states. The utilities claim that the period of unlimited choice in Michigan coincidentally took place at the same time as high gas costs, which made Michigan's rates lower relative to other states, as illustrated in the graphic below provided in comments by DTE Energy, Consumers Energy, and MEGA.

Figure 4: Michigan vs. U.S. National Average Rate with Natural Gas Prices



The utilities claim that New England has experienced problems as a result of a lack of fuel source diversity within the region. Reliance on natural gas for electricity generation spiked prices when demand was high for natural gas to use for heating in New England. Natural gas-fired power plants make up a smaller percentage of generating plants in Michigan, and therefore Michigan is not as sensitive to issues resulting from high demand for natural gas by generators and heating customers.

The chart above shows that Michigan's electricity rates have increased relative to the national average each year since 2009. The following images show various structural drivers that have impacted Michigan's electricity rates since 2008 for Michigan's two largest electric utilities.

Figure 5: DTE Energy Electric Rate Changes

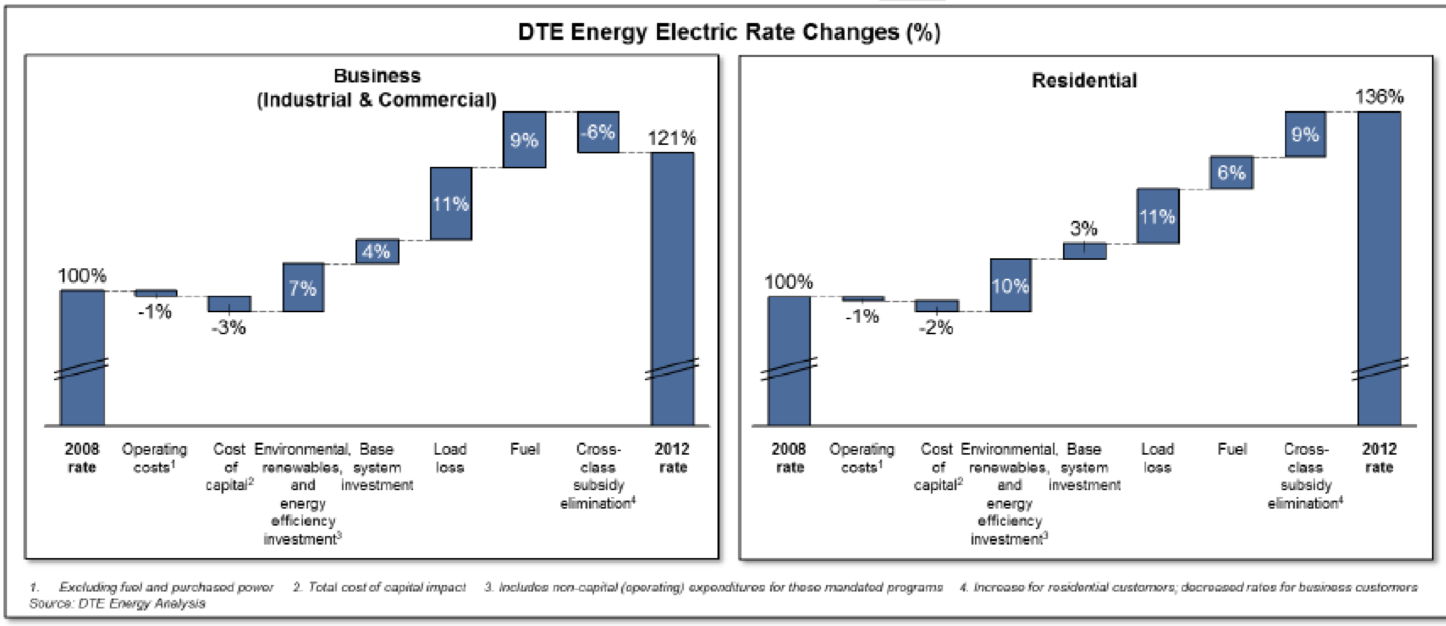
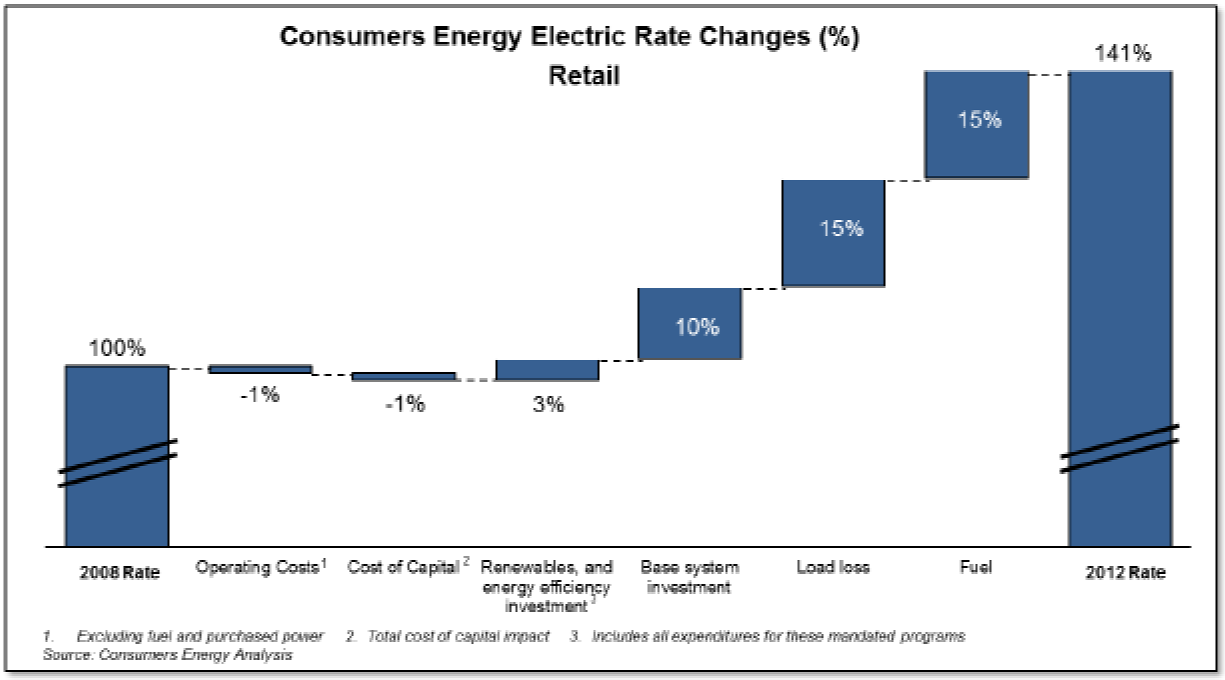


Figure 6: Consumers Energy Electric Rate Changes



Certain drivers pushed rates up, and others mitigated increases. Load loss appears to have had the largest impact on rates over the time-frame utilized by the utilities. As load decreases, whether due to customers leaving utility service to switch to an alternative electric supplier (choice) or leaving the system entirely, there are fewer customers and lower sales over which to spread the fixed costs of a utility. This leads to higher rates for those customers who remain with utility service.

Following load loss, the second largest impact on Michigan electricity rates is shown in Figures 5 and 6 to be increases related to fuel since 2008. A section on increases in Michigan's delivered cost of coal follows. Environmental upgrades, base system investment, renewables and energy efficiency have also contributed to increased rates since 2008. While DTE Energy shows environmental upgrades in the same column as renewables and energy efficiency, it's worth noting that Consumers Energy has captured environmental upgrades in the base system investment column.

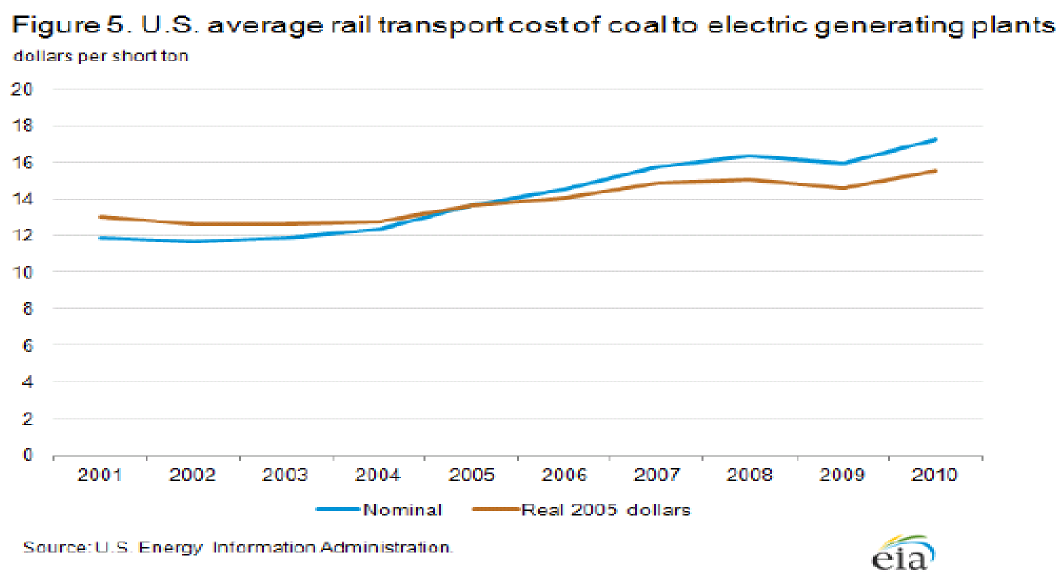
Delivered Cost of Coal

Fuel prices are an element that factor into the electricity prices that are ultimately paid by customers. Over the past several years, prices for coal delivered to Michigan have increased. Several reasons for the increases in Michigan's delivered costs of coal were reported, including transportation costs, production costs and increased coal exports. It was reported that Michigan's total coal costs increased 96% from 2004 to 2012, yet were in line with neighboring Great Lakes states during this time.

Increases in the cost of transporting coal to Michigan have been a primary driver of increases in the delivered cost of coal over the last several years. Transportation costs for coal have increased because of market-based rail pricing and rising diesel fuel prices. According to the Energy Information

Administration (EIA), “The average cost of shipping coal by railroad to power plants increased almost 50% in the United States from 2001 to 2010.” EIA reported that, in 2010, transportation costs represent 40% of the total cost of delivered coal, which means that rising transportation costs directly impact coal costs. Average rail transportation costs per short ton rose from $11.83 to $17.25 from 2001 to 2010. The following EIA graph, submitted by the Union of Concerned Scientists, shows the increase in coal transportation costs over the past several years.

Figure 7: U.S. Average Rail Transportation Cost of Coal to Electric Generating Plants



The use of Powder River Basin (PRB) coal has grown since the 1980s. PRB coal is plentiful and much easier to mine than coal from other regions and therefore has a much lower production cost. Additionally, PRB coal has a lower sulfur content which assists with environmental compliance. Changes in the pricing practices of the railroads that deliver low cost coal out of the PRB region in Wyoming and Montana have been driving the increase in transportation costs.

As PRB coal usage expanded, the two railroads serving the PRB region (the BNSF Railway “BNSF” and the Union Pacific “UP”, or collectively “western railroads”) appeared to compete vigorously for the business, even through periodic rail capacity shortages. The rates charged by the railroads during this time were cost-based, where the railroads would establish rates based on their cost to provide the service, plus a modest profit margin.

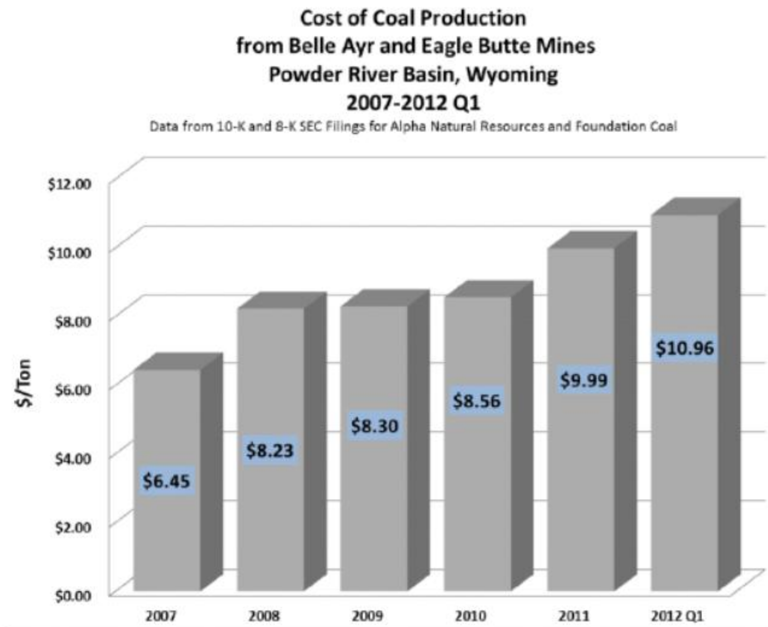
Beginning in about 2004, the rates offered began to transition from cost-based to market-based, which reflects the railroads recognition of the significant price advantage of PRB coal over other fuels, and their belief that an increase in their rates (by increasing the profit margin included in their rates) could be achieved and still allow PRB coal to maintain its price advantage (albeit a lower price advantage) over other fuels. The other Class I railroads that interchange with the BNSF and the UP to complete the delivery of PRB to power plants in Michigan have also moved from “cost based” to “market based” rates. The market-based rates have seen significant increases over recent years.

Much of the coal consumed in the state of Michigan is from the PRB region. Both of the state’s two largest utilities, Consumers Energy and DTE Electric, have had legacy transportation contracts (with cost-based rates) expire in the past several years. These contracts have been replaced with new transportation contracts reflective of the higher market based rates discussed above.

Mileage based fuel surcharges, indexed to the price of diesel fuel, have been implemented by railroads and contributed to the increase in transportation costs. The coal used by Michigan power plants travels a long distance from the point of production to the point of consumption. Coal transportation costs to Michigan are reflective of this longer distance. The fuel surcharges have also contributed to an increase in the cost of transporting coal from the Central Appalachian and Northern Appalachian coal producing regions.

In addition to the increasing costs of coal transportation, production costs have been increasing as well. For both eastern and western coal production, costs are rising as the most easily accessed coal resources are depleted and coal that is more difficult, and therefore more expensive, to mine represents an increasing proportion of delivered coal. These increasing production costs are one factor driving U.S. coal costs upward. The Washington Post cited an observation from the U.S. Energy Information Administration that projected an “upward trend of coal prices [that] primarily reflects an expectation that cost savings from technological improvements in coal mining will be outweighed by increases in production costs associated with moving into reserves that are more costly to mine.” As the chart provided by the Union of Concerned Scientists show below indicates, the cost of mining some Wyoming coal has risen by nearly 70% since 2007:

Figure 8: Cost of Coal Production from Belle Ayr and Eagle Butte Mines

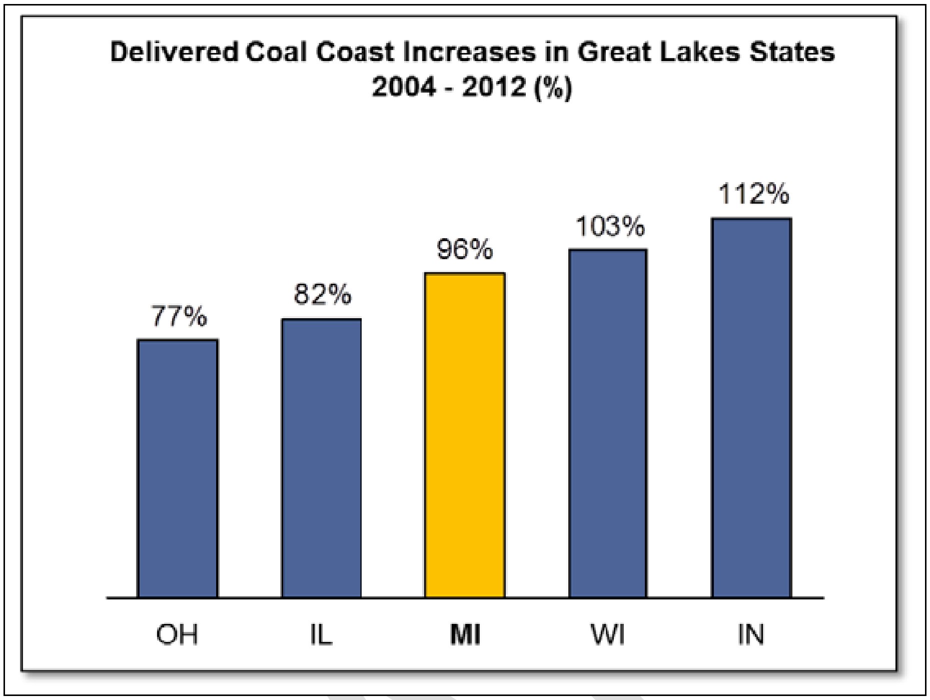


Source: Foster, T., W. Briggs and L. Glustrom. 2012. *Trends in U.S. Delivered Coal Costs: 2004 – 2011.* Clean Energy Action.

Finally, greater coal exports are another important source of upward pressure on coal prices as international coal markets provide new opportunities for U.S. coal mining companies. The upward trend in coal exports combined with declining coal imports are reducing domestic coal supplies, contributing to higher U.S. coal prices.

While Michigan's total coal costs increased 96% from 2004 to 2012, the utilities submitted that they were in line with neighboring Great Lakes states during this time. Much of the increase was realized after 2010 (MI total coal cost increased 28% 2010-2012), as lower-priced legacy transportation contracts expired. Since 2004, Michigan's delivered coal cost increases have been in line with neighboring states. Michigan predominately uses rail or rail-to-vessel transportation; states with direct access to truck or barge delivery (such as Ohio) have seen lower increases. The chart below, provided in a joint response from Consumers Energy, DTE Energy and MEGA, shows the increase in the delivered cost of coal in Michigan compared to surrounding states.

Figure 9: Delivered Coal Cost Increases in Great Lakes States



Submitted by DTE Energy, Consumers Energy, and MEGA
Source: EIA and Ventyx, Percent increases based on $ per MMBtu

Similar data was submitted by the Union of Concerned Scientists:

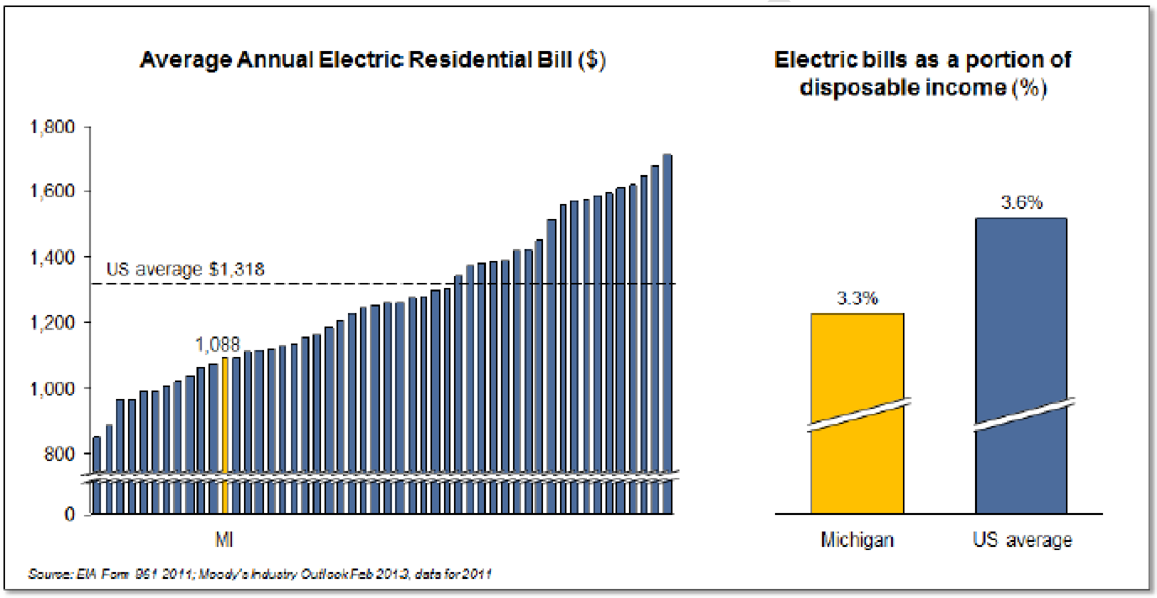
Table 1: Midwest Coal Prices

	2004 Coal Cost $/MMBTU	2011 Coal Cost $/MMBTU	2004-2011 Average Increase / Yr
Illinois	$1.16	$2.01	10.5
Indiana	$1.21	$2.47	14.9
Iowa	$0.90	$1.44	8.60
Michigan	**$1.37**	**$2.81**	**14.7**
Minnesota	$1.06	$1.94	11.8
Ohio	$1.32	$2.29	10.5
Midwest Average	**$1.17**	**$2.16**	**11.83%**
U.S. Total	**$1.34**	**$2.41**	**11.40 %**

While Michigan has experienced significant increases in the delivered cost of coal over the past several years, surrounding states have also experienced significant increases in the delivered cost of coal during the same time period.

The utilities point out that, in spite of Michigan's average rates moving from below the national average to above the national average, Michigan's average annual residential electric bill is below the national average, as shown in the graph below.

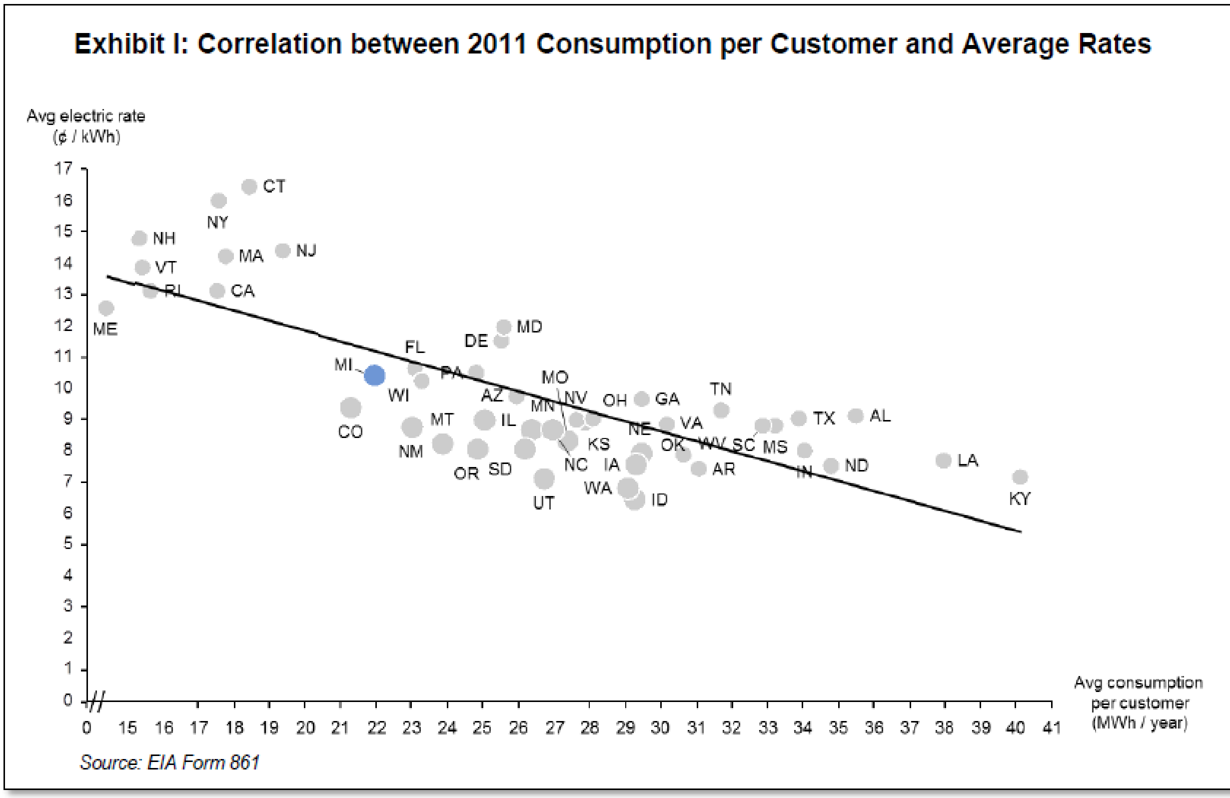
Figure 10: Average Annual Electric Residential Bill



While Michigan's electricity *rates* are higher than many other states, Michigan residential customers generally use less electricity which results in lower *bills*.

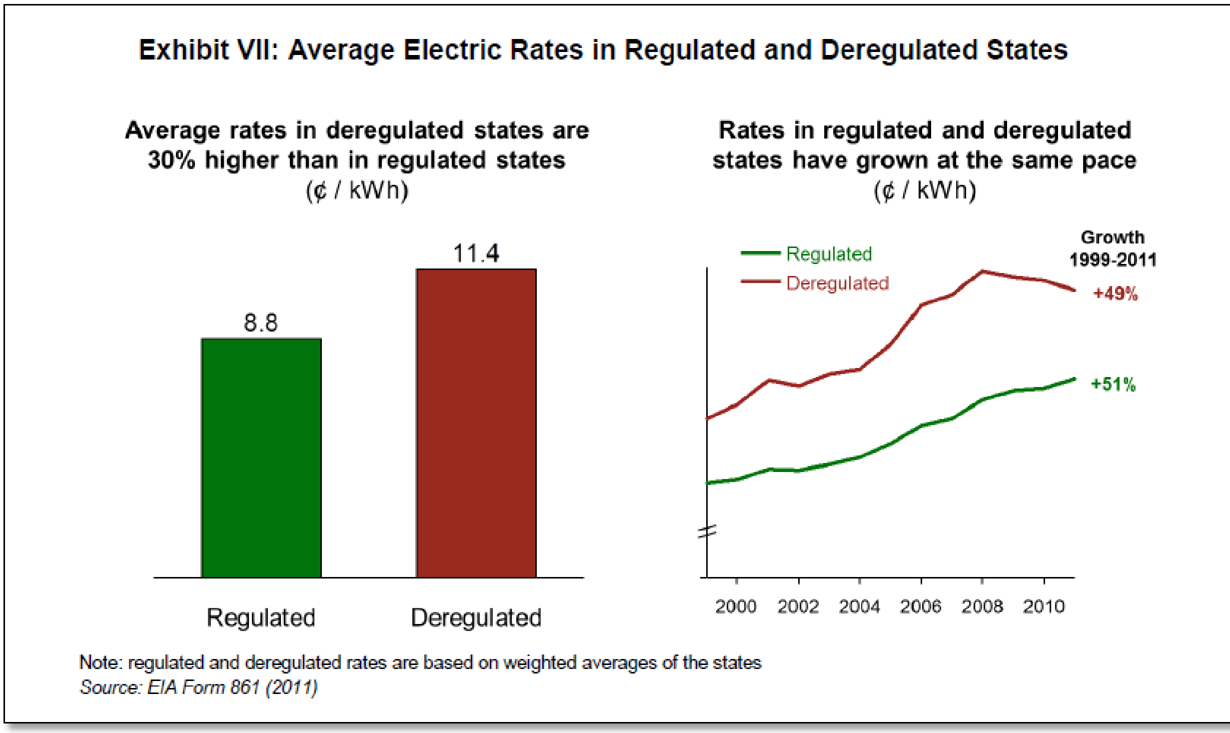
The utilities further explained the structural drivers of utility rates in the response to overall question 1. The utilities claim that 60% of the variation in average rates between states can be explained by electric use per customer. The high fixed costs required to maintain system reliability are recovered from customers in a manner based upon customer usage. Therefore, lower usage means higher rates and vice versa. The relationship between consumption per customer and average rates is illustrated by the following graph:

Figure 11: Correlation between 2011 Consumption per Customer and Average Rates



The utilities also identify three other factors that, combined, explain an additional 25% of the variation in average rates between states: proximity to low-cost coal, access to inexpensive hydroelectric generation, and lack of coal-fired generation. A number of the states that lie below the best fit line on the above graph have delivered coal prices well below the national average. Others have significant amounts of low-cost hydroelectric generation. Many of the states with the highest average rates have very little coal-fired generation, and rely on relatively more expensive generation. The utilities state that deregulation cannot change these structural drivers, and that deregulation has not changed the rate gap between regulated and deregulated states, as shown in the graph below:

Figure 12: Average Electric Rates in Regulated and Deregulated States



Other respondents to overall question 1 have a different view of Michigan's electricity rates, their drivers, and their effect on the state. Dow Chemical Company (Dow) states that Michigan's energy consumption is higher than other states due to manufacturing, climate, and population, which leads to Michigan being more affected by the energy crisis. Dow also points out that Michigan's electric rates are the highest in the Midwest, making the state less attractive to manufacturers, and inhibiting the jobs and economic multiplier effect manufacturers could provide. Dow claims that 2008 PA 286 has provided utilities with an unimpeded ability to push through rate increases by allowing self-implementation and capping competitive supply at 10%. Dow stresses investment in transmission as being a way to get more competitively priced power from out of state to Michigan customers. ABATE echoes Dow's claim that self-implementation has had a negative effect.

<u>Rate Structures for Large Volume Users</u>

A specific question was raised regarding rate structures for large volume users in other states. The only response received was a joint response from Consumers Energy, DTE Energy, and MEGA (the utilities). The joint response focused exclusively on Economic Development rates, rather than the general rate structure for large users. The utilities identify many common factors in the economic development rates utilized by many utilities and states to incent new or expanded load. The rates are often limited in terms of availability, length of application, or amount of load. They also often require a minimum level of employment increase and/or capital investment. The rates are also restricted to new or expanded electricity usage. Similar rates can also be used to target investment, jobs, and load in specific areas, commonly Brownfield sites, vacant industrial property, or specified development zones. The utilities discuss how economic development rates can be designed to prevent other customers from subsidizing those on the rates by ensuring the revenue from the new load covers or outweighs the additional costs to serve said load. Provisions are often included in such rates to protect the benefits they are meant to engender, such as a discount that phases out over several years or claw back provisions.

The utilities identify examples of economic development rates at utilities in several states. Indiana's major utilities have tariff provisions available for economic development, which requires a minimum load increase and employment increase; urban redevelopment, for customers locating in an unoccupied existing building; and brownfield redevelopment. The discounts for these provisions are based on marginal revenue, and they include availability and term restrictions. An Iowa utility, Alliant's Interstate Power and Light, has an economic development rider requiring a cost benefit study and Iowa Utility Board approval for discounts. Energy and customer costs of serving any given customer must be covered by the discounted rate. Alliant's Wisconsin Power and Light's economic development tariff is available to customers receiving state or federal economic development assistance or stimulus, and has an overall annual subscription limitation. In Minnesota, Northern States Power and Minnesota Power have economic development discounts for new load in specified areas. The demand charges are discounted, and the discount phases out over time. The new load must not require significant capital outlay on the part of the utility to qualify. New York's Long Island Power Authority has special rates for companies that expand in or relocate to special zones. Pacific Gas and Electric in California and Florida Power and Light have requested approval for economic development rates.

The utilities state they should have the discretionary ability to offer economic development rates, appropriately designed, with MPSC oversight.

In addition to the above, it should be noted that prior to the introduction of customer choice in 2000, Michigan used a variety of rate approaches, such as special contracts, for large electric and natural gas customers. The Public Service Commission approved dozens of special contracts during the 1990s.[15]

Although the specific details varied by case, the general goal was to enhance economic development in Michigan. The specific advantages cited in the orders approving the special contracts included the

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[15] During the 1990s, special contracts approved by the Public Service Commission include the following: (1) ABTco, Inc., Case No. U-10420; (2) Alchem Aluminum, Inc., Case No. U-9862; (3) Bundy Tubing Corporation, Case No. U-10995; (4) Chrysler Corporation, Ford Motor Company, and General Motors Corporation, Case No. U-10646; (5) CSM Industries, Inc., Case No. U-11267; (6) Dekalb Genetics Corporation, Case,No. U-11302; (7) Escanaba Paper Company, Case No. U-10904; (8) General Motors Corporation, Case No. U-10961; (9) Guardian Industries Corporation, Case No. U-10956; (10) IMC Kalium, Case No. U-12139; (11) James River Paper Corporation, Case No. U-11101; (12) Kraft Foods, Inc., Case No U-11836; (13) Lafarge Corporation, Case. No. U-10948; (14) Lakehead Pipe Line Company, Case No. U-11299; (15) Leprino Foods Company, Case No. U-11256; (16) Lomac, Inc., Case No. U-11266; (17) Lorin Industries, Inc., Case No. U-11259; (18) Macsteel, Case No. U-11254; (19) Manistique Papers, Inc., Case No. U-11079; (20) Michigan Limestone Operations, Case No. U-11258; (21) Munson Medical Center, Case No. U-11257; (22) Ramco Gershenson Properties, Case No. U-11262; (23) Sawyer Lumber Company, Case No. U-11360; (24) Specialty Minerals, Inc,, Case No-10699; (25) Solvay Automotive, Inc., Case No. U-11261; (26) Steelcase, Inc., Case No- U-12060; (27) Stone Container Corporation, Case No- U-11447; (28) Sun Chemical, Case No- U-11268; (29) Tecumseh Products Company, Case No. U-11260; (30) TRW, Inc., Case No. U-11264; (31) The Upjohn Company, Case No. U-11001; (32) Wacker Silicones Corporation, Case No. U-11263; (33) White Pine Mine, Case No. U-10957; and (34) Worthington Industries, Inc., Case No. U-11312.

following (in no particular order): (a) promoting economic and job growth, (b) responding appropriately to competitive challenges in the industry sector, (c) charging prices that exceed the marginal cost of production, (d) providing benefits to other customers and the local economy, (e) ensuring that the adverse effect on other customers is less than other alternatives, (f) giving appropriate consideration to the unique characteristics of the customer, business risks, and value of service, (g) using customer-specific pricing initiatives to meet competitive threats, (h) maintaining customer contribution to system fixed costs, (i) reducing the utility's business risk and strengthening its financial planning, (j) improving the ability to attract new customers and promoting economic development within the local service territory, (k) demonstrating to the financial community a commitment to meet competitive challenges, (l) providing service to customers at rates above variable cost, and (m) maintaining and potentially expanding employment in Michigan. There is a substantial overlap among these reasons, but it is clear that various ratemaking approaches for large volume customers can be used to advance the state's economy.

2008 PA 295 requires rates for all customer classes to be based on their respective cost of service, meaning that one customer class cannot subsidize another. This phased out a historic practice of business customers subsidizing residential customers. Now the state is faced with certain industrial sectors in globally competitive markets that are seeking to maintain their operations in Michigan and are calling for rate relief that would be below their cost of service. Revisiting the 2008 law may provide additional flexibility to promote economic development through discounted industrial rates. The costs and benefits of such policies, if they shift costs to other customers, should be carefully examined. The stakeholder responses did not specifically address this issue.

Impact of Federal Subsidies in Other Regions

Question 11 asks to what extent do federal subsidies impact electric rates for other regions of the country such as the Tennessee Valley Authority or the Western Area Power Administration. The utilities' joint response to this question was again the only response received. According to the utilities, the EIA reports that the Tennessee Valley Authority, Bonneville Power Administration, Western Area Power Administration, Southeastern Power Administration, and Southwestern Power Administration all receive a form of subsidy, in that they are allowed to borrow from the U.S. Treasury directly and have access to lower-cost federal loans and loan guarantees. EIA estimates of the value of these subsidies range from $119 to $987 million. The utilities claim these subsidies do not have a major impact on electric rates, citing their answer to overall question number 1 for the factors that do. (See the previous section on Michigan Electricity Rates.)

Rate Cases

This section presents information related to rate case timeframes and the self-implementation of rates. In utility ratemaking, there is potential for time lag between when the utility makes new investments or increases its costs and when it recovers those costs in rates. Numerous states have instituted and explored various approaches to limit regulatory lag in order to create a more efficient regulatory process.

Rate Case Timeframes

Pursuant to 2008 PA 286, final orders in rate cases must be issued within one year from the date of a complete application. There have been 20 rate case orders since PA 286 was enacted. Based on these cases, the length of time between the rate case filing and a Commission decision has averaged 9.2 months. The national average is 9 months. The average duration of a rate case in Michigan that was fully litigated (cases not settled) was 11.4 months.

The Joint Utility Response reports that "regulatory lag" is due in part to the formal contested case process used to review and approve rate cases, the complexity of the issues and the volume of information prepared, all under regulatory scrutiny. The use of historical information causes regulatory lag because utilities need to wait to prepare the filing until the historical costs are known. The overall lag can be significant given the time needed to prepare a rate case and go through administrative proceedings. Lag can have a greater impact on the utility's financial position when (i) sales are stable or declining, (ii) major capital investments are being made and (iii) regulatory processes result in protracted legal proceedings.

To address regulatory lag, various ratemaking tools have been used by states including pre-approval of new major investments such as power plants, riders to pass through certain types of expenditures, formula-based rates, interim or self-implemented rates, and projected test periods. The ability to file a rate case using a projected test period is key to reducing/eliminating regulatory lag. The use of projected test periods provides the utility with the ability to navigate the rate case process so that Commission-approved rates are in place on day one of the test period, thus aligning utility spending with rate recovery.

The time period allowed for a rate case decision varies from state to state. Many jurisdictions require rate cases to be completed within a set time period. In jurisdictions where there are no such requirements, rate case schedules ranged from 6 to 12 months to be completed.

The Edison Electric Institute (EEI) assembled a list of general rules and common outcomes based on member response from a survey and independent research (see Appendix 2). Exhibit 1 below shows that commissions in 42 of the 50 states typically issue rate case decisions within one year. Commissions in 36 states produce a rate order within 6 to 10 months. Of the eight states that claim a rate case is decided within six months, four states claim that rates are not final and are subject to refund.

EXHIBIT 1

Rate Case Decision Timing, Number of States

Time period allowed for PSC decision	No. of states	No. of states with rates in effect, subject to refund[a]
Less than 6 Months[b]	2	
6 Months	6	4 (CT, GA, OK, TX)
7 Months	6	
8 Months	3	
9 Months	8	1 (MT)
10 Months	13	1 (AR)
11 Months	4	
12 Months	6	
Greater than 1 Year	2	

SOURCE: Edison Electric Institute, Member Survey (February 2013).

[a] In the EEI survey, it was identified that in some states, absent a final PSC Order following a suspension of a period of time, the rates go into effect "subject to refund." It is unclear how long after the rates go into effect that a PSC Order must be issued such that the rates are deemed final. A "subject to refund" approach would seem to indicate that these states have self-implement rules in place, thus requiring a subsequent final order.

[b] Included in this total is Alabama, which has an annual automatic adjustment clause tied to ROE that adjusts rates up or down each January.

Self-Implementation

Prior to PA 286, Michigan law allowed the Commission to grant "partial and immediate" rate relief, also known as interim rates. Interim rate requests were subject to a hearing process and required commission approval. The MPSC applied various standards for determining when to grant interim rates. The interim rate provisions were replaced by PA 286 which allows for self-implementation of rates.

Pursuant to PA 286, if the Commission has not issued an order with 180 days of the filing the utility may implement up to the amount of the proposed annual rate request. For good cause, the Commission may issue a temporary order preventing or delaying a utility from implementing its proposed rates. The amount self-implemented by the utility is subject to refund based on the Commission's final order in the case.

The Joint Utility Response provides Exhibit 2 below which summarizes the 21 cases with and without self- implementation. There were 21 general electric and natural gas rate cases filed between 2008 and 2012. The majority of those cases (14) requested self-implementation and nearly all (13/14) resulted in the self-implementation of rates. Self-implementation has been utilized in every contested case. The Commission reduced the amount of the self-implementation in two of those cases and delayed self-implementation in one case.

EXHIBIT 2

Breakdown of Rate Cases with and
without Self-Implementation (January 2008–April 2013)

	No. of cases
Self-implementation *utilized*	**13**
Final rates higher than self-implemented rates	4
Final rates lower than self-implemented rates (refund)	8
Final order pending	1
Self-implementation *not utilized*	**8**
TOTAL	**21**

SOURCE: Consumers Energy review of MPSC filings (2013).

Appendix 3 summarizes interim rate policies in other states. The majority of states (45) allow for some form of interim or self-implementation of rates. Some states (9) allow interim increases automatically after a specific period of time while others (5) allow interim increases after commission approval. Many states (21) only allow interim rates in the case of emergency or financial stress.

The Association of Businesses Advocating Tariff Equity (ABATE) commented that utilities have the unfettered right to self-implement rate increases under Michigan's current laws. They also commented that Michigan policy on refunds assures that refunds are made by rate class so specific customers will not receive the amount that they are due or even, in certain cases, any refund even though they may have overpaid during the time that the self-implemented rates were in place.

Natural Gas Infrastructure

The Additional Area questions solicited information regarding natural gas storage capacity, storage utilization and the possibility of future expansion of gas storage. Information was also solicited regarding Michigan's natural gas pipeline capacity.

Michigan's Non-renewable Energy Potential

The only non-renewable energy source that is sufficiently available in Michigan is natural gas. Michigan producers supply 15 – 20% of the natural gas that is used in Michigan. All of Michigan's natural gas production is in the Lower Peninsula. Michigan also receives gas from the Texas-Oklahoma panhandle, Louisiana and Canada. Natural gas is obtained from wells; it is then sent to gathering pipelines that, after processing, connect to larger pipelines for delivery to where it is needed. Most gas fields are in geological formations that developed 150 to 200 million years ago.

In order to affordably access Michigan's gas potential, hydraulic fracturing is necessary. Hydraulic fracturing is a process that pumps water, sand and additives into a well under high pressure; as the mixture is forced into the surrounding rock, it fractures the rock, creating additional openings through which the gas can flow. Many oral and written comments and concerns regarding the safety and environmental impact of hydraulic fracturing were received in this process. Although many concerns were raised by the public, Michigan producers have used hydraulic fracturing since the 1950s and continue its use today. The Michigan Department of Environmental Quality and the Michigan Public Service Commission are responsible for ensuring the safety of gas production in the state. The Graham Sustainability Institute at the University of Michigan has released technical reports for comment regarding hydraulic fracturing in Michigan.[16]

Michigan's underground geological features also provide an excellent opportunity for gas storage. The amount of available natural gas storage in Michigan is significant. With about 649 billion cubic feet of storage capacity, Michigan has more than any other state. Because natural gas can be put into storage during the summer months when there is less demand, it allows for more efficient use of transmission pipelines and helps stabilize prices. All but two of Michigan's 55 storage fields were once producing fields. Michigan's storage fields have a high porosity, which makes them among the best in North America.

Natural gas plants are considered to be economically and operationally viable. The Energy Information Administration (EIA) makes projections of levelized costs for various types of electric generation. In its Annual Energy Outlook 2013 Early Release, EIA estimated the levelized cost of a natural gas combined cycle plant to be in the range of $65.60 to $67.10 per MWh. The EIA costs are in 2011 dollars for plants entering service in 2018 and are overnight cost estimates. The Commission Staff, with input from a group of electric providers, developed a combined cycle natural gas plant levelized cost of $66.23 per MWh in 2013 dollars for a plant entering service in 2016. The estimated cost of a natural gas plant compares favorably to other types of generation. Consumers Energy recently filed an application at the

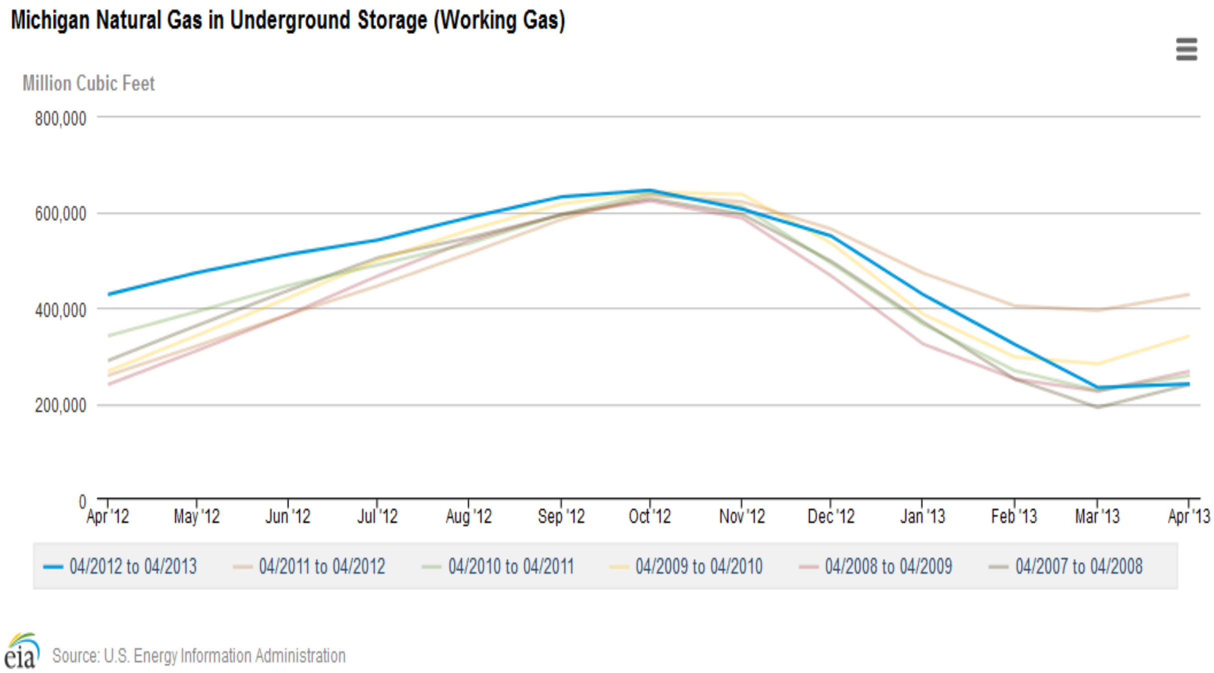
[16] http://graham.umich.edu/knowledge/ia/hydraulic-fracturing.

Michigan Public Service Commission requesting a Certificate of Need for a 700 MW combined cycle natural gas plant.

Natural Gas Storage

According to the Energy Information Administration (EIA), roughly one third of working gas still remained in Michigan storage fields at the end of the 2013 heating season. The warm winter in 2012 left even more gas remaining in storage. The chart below shows that the lowest the working gas storage levels have been in the past five years is around 200,000 Mcf.

Figure 13: Michigan Natural Gas in Underground Storage



A large portion of the available storage in Michigan is reserved for the bundled regulated utility natural gas and alternative gas provider customers. In warmer years, if gas is unused, utilities may be able to sell some of that gas on the open market. Storage capacity in excess of that reserved for Gas Cost Recovery (GCR) and Gas Customer Choice (GCC) customers is generally sold under contract through marketers. It should also be noted that although the entire storage capacity may not be utilized through the course of a heating season, storage fields are often 100% utilized on a peak winter day. Because of the drastic increase in demand on very cold days, Michigan utilities rely on storage fields to provide supply volumes at a high rate that cannot be achieved by transporting gas over long distances.

Theoretically there is room for gas storage expansion in Michigan because there are depleted gas reservoirs that could be converted to storage if it is economically feasible to do so. The economic feasibility usually depends on the location of the reservoir and its geologic characteristics. In many cases, there would need to be additional infrastructure and pipeline capacity added in order to convert and utilize these reservoirs. A less expensive alternative has been implemented in recent years to increase storage volumes in small amounts. Storage field operators have been able to safely increase the pressure of the fields and inject a larger volume of gas. Depending on the geology, a storage field can withstand a certain amount of pressure without risking gas migration or damage to the reservoir. Currently, there is no need to expand storage for the regulated utility customers and there is not enough demand outside of the Michigan market to justify large investments in storage expansion by non-regulated companies.

Natural Gas Pipeline Capacity

Currently, there is sufficient in-state pipeline capacity to move natural gas around the state and to satisfy Michigan's demand as a whole. However, there are various factors that can impact the natural gas supply capacity and the demand on a short or long term basis. Supply into Michigan can be impacted by outages on upstream infrastructure or disruptions in natural gas producing regions in the U.S. (See maps below of interstate pipelines and shale plays.) Generally these issues can be mitigated by allowing the gas supply to be shifted within the existing pipeline network depending on the circumstance. Within the state, gas supply to city gates can be directly affected by unplanned system outages. Although these instances are usually corrected quickly with little or no impact to customers, there is the potential for a longer shortage depending on the outage and the demand.

Figure 14: Major Shale Plays in the Lower 48 States

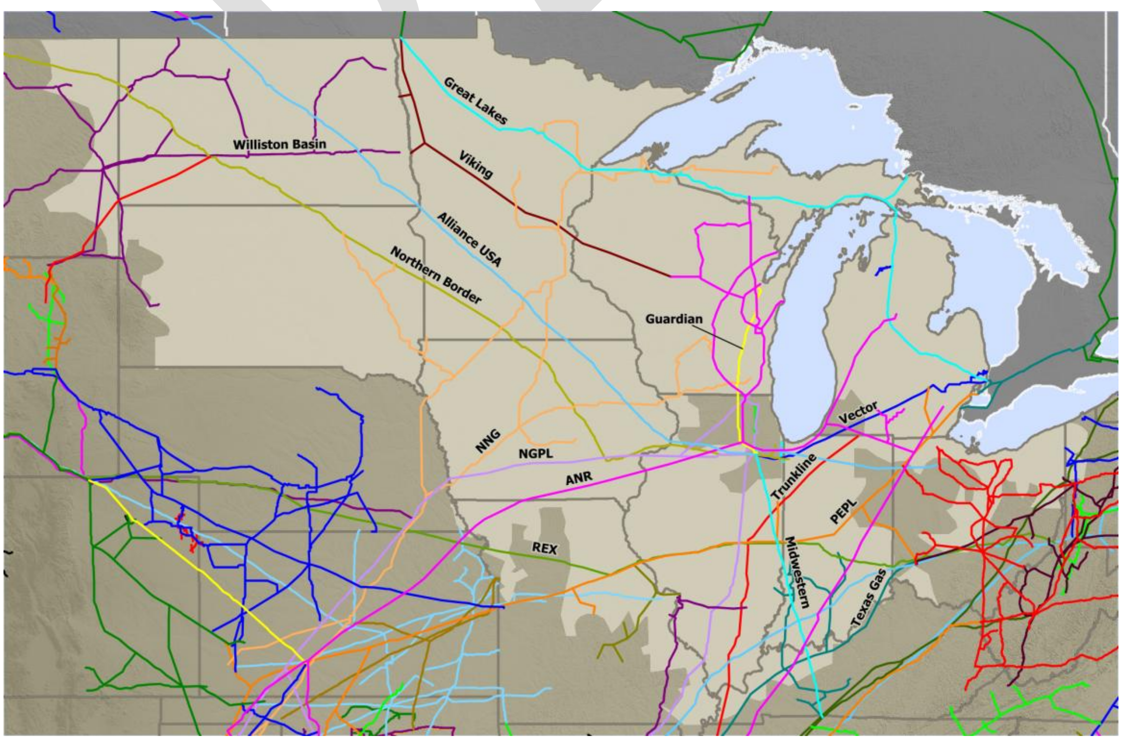
Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

In the short term, demand in Michigan primarily depends on the weather. In a cold winter, more gas is consumed and more supply is needed. Because of Michigan's storage capabilities, a majority of the gas consumed in the winter comes from storage fields. This means that utilities must react to outages differently depending on the time of year and where the supply is available.

Long term demand in Michigan is also affected by a variety of factors. Currently, the low price of gas and the increase in shale production provides increased incentive to use gas for applications other than heating. Specifically, Michigan is currently experiencing a compliance push to retire and replace coal-fired electric generation with natural gas fired generation, mainly due to environmental regulations and the price of gas. Each individual addition of gas-fired generation to the grid would lead to a study to determine whether the plant addition would cause the need for additional gas infrastructure within the state. This transition is ongoing but if the electric grid becomes more dependent on gas generation, additional planning and infrastructure will be needed to provide gas supply on peak days. These increases in gas demand are analyzed by transmitters and utilities in the state, and new pipeline infrastructure is constantly being considered to meet demands most efficiently. Currently it is anticipated that the increase in regional shale production will be available to Michigan. If this production continues to grow, there will likely be an increase in the volume of gas passing through Michigan to Canada and surrounding states.

There are many areas of Michigan that are not connected to a natural gas system because in the past it has not been economic to install the infrastructure and switch from other heating fuels. Recently, the decline in new home construction and lower gas prices has driven utilities to seek new customers elsewhere. As a result, utilities are now taking a more proactive approach in finding new customers and extending their systems while taking advantage of low prices. Customers benefit from the lower energy costs in the long term and the utility is able to grow its system through a Customer Attachment Program. There are still many Michigan residents that have chosen not to connect to a natural gas main and a large number of potential gas customers on alternative heating fuel sources who are without natural gas service, but this is due to the current lack of gas distribution infrastructure, not transmission system capacity.

Figure 15: Major Gas Pipelines into Michigan



As shown above, several pipelines currently serve Michigan allowing for the ability to source gas from multiple different regions. Michigan has sufficient pipeline capacity to meet near-term needs, notwithstanding the caveats discussed previously, such as an increase in natural gas-fired generation within the state.

Summary

Governor Snyder's special message on Energy and the Environment last year specifically requested that information be gathered to assist in the review of current renewable energy policy, energy efficiency policy, and electric choice policy. Governor Snyder also articulated that Michigan's energy future should be based upon the principles of reliability, adaptability, and protecting the environment. This report outlines some additional areas within the energy policy space that could be considered when reviewing future energy policy, including reliability, electricity rates and prices, and natural gas infrastructure. Reliability and affordability are of prime importance to customers and that is expected to continue. Michigan is uniquely positioned with significant natural gas infrastructure that should be considered in the context of future policy decisions. While developing a cohesive future energy policy for Michigan in the areas of renewable energy policy, energy efficiency policy, and electric choice policy, the additional areas outlined in this report should be taken into consideration.

Appendix 1:
Excerpts from MPSC Electric Reliability Rules

R 460.722 Unacceptable levels of performance during service interruptions.

It is an unacceptable level of performance for an electric utility to fail to meet any of the following service interruption standards:

(a) Considering data derived through the amalgamation of data from both normal and catastrophic conditions, an electric utility shall restore service within 36 hours to not less than 90% of its customers experiencing service interruptions.
(b) Considering data including only catastrophic conditions, an electric utility shall restore service within 60 hours to not less than 90% of its customers experiencing service interruptions.
(c) Considering data including only normal conditions, an electric utility shall restore service within 8 hours to not less than 90% of its customers experiencing service interruptions.
(d) Considering data derived through the amalgamation of data from both normal and catastrophic conditions, an electric utility shall not experience 5 or more same circuit repetitive interruptions in a 12 month period on more than 5% of its circuits.

R 460.744 Penalty for failure to restore service after an interruption due to catastrophic conditions.

Rule 44. Unless an electric utility requests a waiver pursuant to part 5 of these rules, an electric utility that fails to restore service to a customer within 120 hours after an interruption that occurred during the course of catastrophic conditions shall provide to any affected customer that notifies the utility of the interruption with a bill credit on the customer's next bill. The amount of the credit provided to a residential customer shall be the greater of $25.00 or the customer's monthly customer charge. The amount of the credit provided to any other distribution customer shall be the customer's minimum bill prorated on a daily basis.

R 460.745 Penalty for failure to restore service during normal conditions.

Rule 45. Unless an electric utility requests a waiver pursuant to part 5 of these rules, an electric utility that fails to restore service to a customer within 16 hours after an interruption that occurred during normal conditions shall provide to any affected customer that notifies the utility of the interruption a bill credit on the customer's next bill. The amount of the credit provided to a residential customer shall be the greater of $25.00 or the customer's monthly customer charge. The amount of the credit provided to any other distribution customer shall be the customer's minimum bill prorated on a daily basis.

R 460.746 Penalty for repetitive interruptions of the same circuit.

Rule 46. (1) Unless an electric utility requests a waiver pursuant to part 5 of these rules, a customer of an electric utility that experiences and notifies the utility of more than 7 interruptions in a 12-month period due to a same-circuit repetitive interruption shall be entitled to a billing credit on the customer's next bill. The amount of the credit provided to a residential customer shall be the greater of $25.00 or the customer's monthly customer charge. The amount of the credit provided to any other distribution customer shall be the customer's minimum bill prorated on a daily basis.
(2) Following provision of the billing credit to a customer experiencing more than 7 interruptions in a 12-month period due to a same-circuit repetitive interruption, the electric utility's interruption counter shall be reset to zero to ensure that another credit to the customer will be processed only after the occurrence of another 8 interruptions in a 12 month period.

Appendix 2:
Summary of State Rules for Rate Case Decisions

Line No.	State	Policies
1	Alabama	Utilities operate under alternative regulatory schemes, so cases have not been filed. However, if a traditional rate case were filed, the commission can suspend rates for 6 months from the proposed effective date, which generally must be 30 days after the initial filing.
2	Alaska	The commission must issue a decision with 450 days after a complete filing. The commission may extend the timeline for up to 90 days if all parties consent to the extension, or the commission finds good cause exists to extend. If an order is not issued within the timeline or the extended timeline, the application is deemed approved.
3	Arizona	The commission must decide major rate cases within 12 months of the Staff's certification of the sufficiency of the filing. A rate case decision for a major utility must be issued within 360 days from the date "a utility's rate filing is determined to be sufficient."
4	Arkansas	The commission must decide a rate case within 10 months of the filing, after which the utility can place the rates into effect, subject to refund.
5	California	General rate cases are limited to 18 months. However, there are no penalties or enforcement mechanisms.
6	Connecticut	Utilities are required to issue a notice of intent to file 30-60 days before the filing of a rate application. The commission can extend the normal 150-day extension to 180 days upon notification to all the parties. If the commission fails to implement an order by the end of the suspension period, an increase may be implemented, subject to refund.
7	Colorado	A request for a rate change must be filed at least 30 days before the proposed effective date. The commission can suspend the tariffs for 210 days from the proposed effective date, after which the rates become effective.
8	Delaware	The commission attempts to complete rate cases within 7 months from the date of filing, after which, under certain conditions, the utility may place the rates into effect.
9	District of Columbia	No statutory time frame within which the commission must act on rate applications. However, the commission has adopted a standard of completing cases within 90 days of the close of the record.
10	Florida	The commission can suspend a rate increase for a maximum of 8 months from the filing date. Commission can issue expedited decisions under certain circumstances
11	Georgia	A utility is required to give 30-day's notice when filing for a rate increase. The commission can suspend the proposed increase for a maximum of 5 months more, after which the utility can implement rates, subject to refund
12	Hawaii	There is no statutory time limit within which a rate case must be completed, but the commission must "make every effort" to issue a decision within 9 months.
13	Idaho	Utilities must file a notice of intent to file a rate case 60 days before the filing. The commission must render a decision within 7 months of the filing. The commission can then suspend the rate request an additional 60 days.
14	Illinois	Utility rate case decisions must be issued within 11 months of a filing.
15	Indiana	No statutory time limit for commission action on rate requests, but the commission has established a 10-month target timeframe.
16	Iowa	The commission is required to render a final rate case decision within 10 months of the filing date, but may extend that time, under certain circumstances.

Line No.	State	Policies
17	Kansas	The commission must act to suspend a rate case within 30 days of its filing for a maximum of 240 days, after which the rates become effective. If hearings are still in session at the end of the 240 days, the commission can extend the suspension period an additional 20 days. If the company substantially amends its filing, the commission can deem the filing a new application and restart the 240-day period. The utility can also consent to an extension of the 240-day period.
18	Kentucky	Application must be filed no less than 30 days before the proposed effective date of the new rates. The commission is authorized to suspend rates up to 5 months, if the utility proposes to use a historic test year, and 6 months, if the utility proposes to use a forecasted test year. At this point, the utility can implement rates, subject to refund. After 10 months from the original filing date, the rates become permanent.
19	Louisiana	Commission is constitutionally required to act on a rate application within 1 year of the filing date, after which, the utility may implement rates under bond and subject to refund.
20	Maine	A utility must file for a rate increase at least 30 days before the requested effective date. The commission can suspend rates for a maximum of 8 months from the requested effective date.
21	Massachusetts	The commission is required to issue a final decision in a rate case within 6 months of a filing, after which rates become effective.
22	Maryland	Utility is required to give 30 days' notice when filing for a rate change. The commission can suspend rates for 150 days beyond the 30-day period, and then suspend for an additional 30 days. If no rate action is taken after 210 days, the utility may place rates into effect.
23	Michigan	The commission has a 12-month deadline within which to complete a case or the rates become approved.
24	Minnesota	A written commission order must follow within 8 months of a 60-day suspension period after the filing of a rate case. After this, the rates may be implemented as permanent. The commission can suspend a rate case beyond this 10 month total under certain circumstances.
25	Mississippi	The commission must decide a rate case within 120 days of the filing of a notice of intent. After that, the rates may be implemented on a temporary basis.
26	Missouri	Utilities seeking to increase rates must file tariffs 30 days before the proposed effective date. The commission can then suspend the rates for 10 months. If the commission has not issued an order within 11 months of the original filing, the rates go into effect, not subject to refund.
27	Montana	A commission must render a final decision in a rate case within 9 months of the filing, after which the utility may place the rates into effect subject to refund.
28	Nebraska	After a rate case is filed, a negotiation period of up to 90 days is initiated, after which the commission has 210 to issue a decision on the rate request. The suspension period can be extended an additional 60 days.
29	Nevada	State law requires the commission to render a decision within 7 months of the filing date, after which the rates become effective.
30	New Hampshire	If the commission has not acted on a general rate case increase request within 6 months following the proposed effective date (generally 30 days after the filing), the utility can place the requested increase into effect. If the commission has not acted by a year from the proposed effective date, the rates become permanent.
31	New Jersey	A utility must give 30 days' notice of the effective date of a rate filing. The commission may suspend a decision 8 months, but may further extend the procedural schedule.

Line No.	State	Policies
32	New Mexico	The commission must act to suspend the proposed rates within 30 days of a rate filing or the rates become effective. If the commission does not render a decision within ten months of the filing, an increase may be placed into effect on a permanent basis.
33	New York	The commission must issue a decision within 11 months of a filing.
34	North Carolina	The utility must submit a rate petition 30 days before the requested effective date. The commission is then required to act on the rate petition within 270 days of the requested effective date, bringing the total elapsed time from filing to decision to approximately
35	North Dakota	The commission can suspend rates within 30 days of a utility's filing for a maximum of 6 months, making the maximum rate case duration 7 months.
36	Ohio	A utility is required to give 30 days' notice prior to requesting a rate increase. A utility may not tender a Notice of Intent to file a new rate case until the Commission has completed action on a previous case or until 275 days have elapsed since the filing of a prior application, whichever occurs sooner. The PUC generally completes cases within nine to 10 months after the filing.
37	Oklahoma	By law, the commission must issue a decision within 180 days of a utility-initiated general rate filing, after which the utility may place rates into effect, on an interim basis, subject to refund.
38	Oregon	Within 30 days following a rate filing, the commission can suspend a requested increase for a maximum of 6 months. The commission can then suspend the rates again for an additional 3 months, bringing the maximum proceeding time to 10 months
39	Pennsylvania	Utility is required to give 30 days' notice when filing for a base rate increase. The case is initially suspended for 60 days while the commission evaluates the application for completeness, then the case can be suspended for up to 7 months.
40	Rhode Island	Commission must suspend rate increase applications within 30 days of the filing for a maximum of 8 months. The commission must issue a final order within 90 days of the end of the hearings. Decisions are generally issued 9 months from the initial filing.
41	South Carolina	The commission is required to issue a ruling within 6 months after a filing, but may extend the 6 months an additional 5 days. After this the utility may implement rates, subject to certain conditions. Commissions may allow utilities to implement rates without hearings under certain circumstances. Rate increase applications may be filed no more frequently than every 12 months.
42	South Dakota	Commission must issue a rate case decision within 6 months of the filing date, after which the utility may implement the rates, subject to refund. If an order is not issued within one year of the filing date, the rates become permanent.
43	Tennessee	The commission must act on a rate application within 9 months of the filing date. After 6 months with no action, the utility may place the rates into effect, subject to refund. At the end of 9 months, the utility may implement permanent rates.
44	Texas	Utilities must submit a filing 35 days before the effective date of the new rates. The commission can suspend a rate increase for up to 150 days beyond the proposed effective date, bringing the total number of days to 185, after which the utility can place the rates into effect subject to refund. The 185 days can be extended further under some circumstances, subject to the utility's approval. Also, the PUC monitors the utilities' earnings on an annual basis. Each May, the utilities file financial data for the previous calendar year. The PUC Staff then conducts a review of these filings and makes recommendations to the commission concerning whether there is a potential for over-earnings. If so, the PUC may require the utility to tender a "complete rate filing package" in order to determine whether a rate change is necessary. Once such a filing is submitted, the 185-day clock applies.
45	Utah	The commission must act on rate petitions within 240 days of the initial filing, after which the proposed tariffs become effective. Within 30 days of the filing, the commission can detail deficiencies in the application and suspend the 240-day statutory period, to be resumed when the application is complete.

Line No.	State	Policies
46	Vermont	A utility must allow 45 days from the date of the filing to the proposed effective date of the rates. Utilities can place rates into effect if the commission has not reached a final decision within 7 months of the proposed effective date of the rates.
47	Virginia	Commission must render a decision on a rate increase request within 9 months of a filing. Utilities may also file for expedited rate relief, subject to certain parameters.
48	Washington	The utility must file 30 days before the proposed effective date. The commission can suspend rates beyond the proposed effective date for a maximum of 10 months, after which the rates become effective.
49	West Virginia	An application must be filed 30 days before the proposed effective date, and the commission can suspend a filing for up to 270 days after the proposed effective date. If an order is not issued by the end of the suspension period, rates may be implemented without refund obligation.
50	Wisconsin	No statutory time limit on rate cases, but the commission has decided most cases within 9-12 months.
51	Wyoming	The commission must issue a rate order within 10 months of a filing.

SOURCE: Information provided by Casimir Bielski (EEI) based on member surveys and augmented by additional research.

- Provided in a joint response from the Michigan utilities

Appendix 3:
Summary of State Rules for Rate Case Self-Implementation and Interim Rates

Line No.	State	Self-Implement / Interim Rates
1	Alabama	Emergency interim rate increases are permitted.
2	Alaska	Interim increases are permitted following a commission finding of "irreparable harm" to the company absent such an increase. The ARC has approved interim increases in certain instances.
3	Arizona	A rate case must be decided within 12 months following Staff's certification of the sufficiency of the filing. Interim rates can be issued if the decision is not rendered within this time.
4	Arkansas	The commission must issue a decision within 60 days of a request for an interim increase, but an immediate and impelling necessity is required for the increase to be authorized. Interim increases have rarely been sought.
5	California	The commission can authorize interim increases and can specify whether those increases will be subject to refund or firm, but no increases have been requested in recent years.
6	Connecticut	Interim increases have rarely been sought. The utility must demonstrate that a financial emergency exists.
7	Colorado	Refundable interim rate increases are occasionally granted by the Commission.
8	Delaware	Modest interim rate increase, under bond, can be put into effect 60 days after the filing date.
9	District of Columbia	Not able to verify.
10	Florida	Interim rate increases are permitted by law and have frequently been authorized, usually becoming effective three months after a filing. Emergency conditions are not necessary for an interim increase to be authorized. An interim increase is subject to refund with interest and is generally based on the utility's achieved rate of return and cost of capital for the most recent 12-month period and the low end of the authorized return range in the previous rate case.
11	Georgia	The commission can authorize interim increases under certain circumstances, but none have been sought in recent years.
12	Hawaii	State law calls for interim rates to be implemented, subject to refund with interest, ten months after the filing date to reflect any increase that the commission thinks the utility is probably entitled to. The commission has authorized substantial interim increases in recent cases.
13	Idaho	The commission can allow the utility interim rate increases, but the utility must demonstrate a financial emergency or immediate need. Interim rate increases have rarely been requested.
14	Illinois	Interim rate increases can be implemented after 120 day review, subject to refund, after a showing of financial need by the utility. Interim increases have rarely been sought.
15	Indiana	The commission can authorize an interim rate increase, subject to refund, in circumstances of financial emergency, but interim increases have rarely been sought.
16	Iowa	Utilities can implement interim rate increases, subject to refund, and such interim rate increases have been implemented in most cases. These interim rates can be implemented 90 days after the filing date based on revenue requirement as established by the commission or ten days after the filing date based on previously established regulatory principles.

Line No.	State	Self-Implement / Interim Rates
17	Kansas	The commission has authority to grant interim increases, but utilities have seldom requested interim increases.
18	Kentucky	The commission can grant interim increases if it finds that the credit or operation of the utility would be materially impaired. Interim increases have seldom been requested.
19	Louisiana	Interim rates are permitted but seldom requested.
20	Maine	The commission can permit interim increases, subject to refund, for amounts not subject to reasonable dispute, if it determines that the utility will experience financial harm that cannot be remedied within the normal rate process. There have been no requests for interim increases over the past several years.
21	Massachusetts	A company must demonstrate irreparable harm to the company or customers in order to be able to implement interim rates. Such rates have rarely been sought.
22	Maryland	The commission can allow interim rate changes, but they have rarely been sought.
23	Michigan	Utilities can implement a proposed rate change on an interim basis 180 days after a filing, if the utility uses a historical test year. If a utility uses a forecasted test year, the utility cannot implement an interim rate increase before the beginning of the test year. For good cause, the commission may issue a temporary order preventing or delaying a utility from implementing its proposed rates.
24	Minnesota	Utilities can implement interim rates 60 days after filing. Such rates are subject to refund, must be based on the ROE authorized in the company's previous case, and must be of "like nature and kind" to rates in the company's previous case. An interim increase cannot be permitted until four months after the final order in the previous case. Interim increases have typically been requested and approved.
25	Mississippi	Interim increases have rarely been requested.
26	Missouri	Interim increases may be authorized if a company can demonstrate an emergency or near emergency situation. Interim rates are really sought or authorized.
27	Montana	In most rate cases the commission has authorized interim rates, subject to refund, usually within two to four months after the filing.
28	Nebraska	Natural gas utilities may implement an interim rate increase 60 days after a filing if the utility is negotiating with the municipalities, and 90 days after filing if rates are not being negotiated.
29	Nevada	Interim rate increases have not traditionally been requested.
30	New Hampshire	If the commission has not acted on a filed case within six months following the proposed effective date, the utility may put the increase into effect, under bond. Temporary increases may be granted if the utility demonstrates it is not earning a reasonable return. Temporary increases have generally been granted when requested.
31	New Jersey	The commission can authorize utilities to implement interim increases, but a finding of irreparable harm is generally required.
32	New Mexico	Interim rate increases have rarely been authorized. The utility must demonstrate that it will experience immediate and irreparable injury.
33	New York	Interim or emergency rate hikes are permitted only if the utility can demonstrate that its ability to raise capital or maintain services would be impaired. Interim increases have rarely been sought.
34	North Carolina	Interim increases can be requested, if the utility can demonstrate severe financial deterioration and that emergency conditions exist. No interim increases have been requested in years.
35	North Dakota	State law allows interim increases to be implemented within 60 days of a filing, subject to refund with interest. Utilities generally file for interim increases.

Line No.	State	Self-Implement / Interim Rates
36	Ohio	The commission can allow a utility an interim increase if the utility demonstrates a financial emergency.
37	Oklahoma	If the commission fails to issue a decision in 180 days, the utility may implement up to the full amount of the request, subject to refund. Interim rate increases are also permitted at the commission's discretion, but are seldom requested.
38	Oregon	Commission is allowed by law to authorize interim increases, if the utility is under severe financial stress.
39	Pennsylvania	The commission may authorize an interim increase if the commission determines that the increase is necessary for the utility to maintain financial stability and service reliability. Commission decisions on interim petitions must be issued within 30 days. Interim increases have not been requested.
40	Rhode Island	Commission has statutory authority to approve interim increases subject to refund, but interim rates have seldom been requested.
41	South Carolina	Not able to verify.
42	South Dakota	Utilities can issue interim increases, subject to refund, if the commission does not issue a rate case decision within six months of the filing. The commission cannot order a refund of interim rates beyond 12 months of the filing.
43	Tennessee	If no rate action has occurred within six months of a filing, a utility can put a requested increase into effect, subject to refund. The commission has authority to grant an interim increase, if a financial emergency exists. Utilities have rarely requested interim increases.
44	Texas	Not able to verify.
45	Utah	The commission can grant an interim increase, subject to refund. Requests for interim increases must be submitted within 90 days of the commission's determining the rate filing is complete. To get the increase, a utility must present a compelling case without substantive opposition that serious financial harm will occur without the interim increase. The commission has occasionally authorized such increases.
46	Vermont	The commission has authority to allow interim increases. If a requested interim increase is not denied, the utility can place the interim rates into effect, subject to refund. Interim increases have seldom been requested.
47	Virginia	An expedited rate proceeding allows the utility to implement an interim rate change, subject to refund, after 30 days.
48	Washington	The commission can grant interim increases if the utility's financial security has deteriorated to the point that it would cause harm to customers and stockholders. Few such increases have been sought.
49	West Virginia	Interim increases may be authorized, subject to refund, but are rarely requested.
50	Wisconsin	Interim rate increases are permitted, subject to refund, but none have been requested in recent years.
51	Wyoming	Commission has the authority to grant temporary increases under bond and subject to refund following a showing of immediate financial need.
52	Ontario	Utilities have to apply to implement interim rates (or make current rates interim). Applications for interim rates are typically addressed as a preliminary hearing issue, involving written submissions.

SOURCE: Information provided by Casimir Bielski (EEI) based on member surveys and augmented by additional research

- Provided in a joint response from the Michigan utilities